COSTS OF REDUCING METHANE EMISSIONS IN THE UNITED STATES

PRELIMINARY REPORT

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1. INTRODUCTION

1.1 Objective

The objective of this report is to estimate the cost of reducing methane emissions in the United States. Costs are estimated from the perspective of private decision makers. The results are summarized in terms of the emissions reductions that can be achieved for a range of scenarios involving energy price changes or changes in the value of carbon expressed in $/ton of carbon equivalent. These results are designed to be used as input to comprehensive analyses of the cost of achieving specific limits of annual greenhouse gas emissions in the United States.

1.2 Scope

This cost analyses focuses on four sources of methane emissions in the United States:

- landfills;
- coal mining;
- natural gas systems; and
- livestock manure management.

As shown in Exhibit 1, these four sources accounted for approximately 22 teragrams (Tg)[1] of methane emissions in 1990, or nearly 75 percent of the U.S. total in that year.

Exhibit 1: Methane Emissions in the United States (Tg of Methane)

Source	1990	1995	1996
Landfills	9.8	11.1	11.4
Coal Mining	4.2	3.5	3.3
Natural Gas Systems	5.7	6.0	6.0
Livestock Manure Management	2.6	2.9	2.9
Livestock Enteric Fermentation	5.7	6.1	6.0
Petroleum Systems	1.2	1.2	1.2
Other Sources	1.3	1.4	1.4
Total	30.6	32.4	32.1
Source: EPA (forthcoming).			

Emissions can also be reduced from the other main emissions sources, including petroleum systems and livestock enteric fermentation. For example, emissions from petroleum systems can be reduced using some of the technologies and practices that reduce emissions from natural gas systems. Emissions from livestock enteric fermentation can be reduced using techniques and practices that improve production efficiency in the dairy and beef industries. Additional research is ongoing to incorporate the opportunities for reducing emissions from these sources into this analysis. By omitting these opportunities, this analysis under-estimates the potential to reduce methane emissions in the United States.

1.3 Methodology Overview

The methodology used to determine the cost of emissions reductions for each of the sources is as follows:

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[1] One teragram (Tg) equals a million metric tons or 10^{12} grams.

- *Estimate baseline emissions*. Baseline emissions were estimated for each source. The baseline represents the emissions anticipated in the absence of efforts to reduce emissions.
- *Identify emission reduction technologies and practices*. A set of technologies and practices for reducing emissions is identified for each source. Each technology and practice is characterized in terms of its emission reduction, its capital cost, and its operation and maintenance (O&M) cost. Any cost savings associated with the technology or practice are also estimated, such as the value of methane collected and available for use as energy. The costs and savings are estimated from the perspective of private decision makers, and thus do not, for example, examine benefits associated with CO_2 reductions due to replacement of fossil fuels with methane gas.
- *Estimate the cost of reducing emissions per ton of emissions reductions*. Discounted cash flow analysis was performed to estimate the cost of reducing emissions for each technology and practice. The cost estimates are expressed in $/ton of carbon equivalent and represent the cost to private decision makers to implement each technology or practice.
- *Sum the emissions reductions*. The total emission reduction for a source is estimated by summing the reductions from the individual technologies and options. For a given emission reduction value, the emission reduction options that cost less than that value are identified. For example, at a value of $50/ton of carbon equivalent, the total emission reduction is estimated to be the sum of the emissions reductions from the technologies and practices that cost less than or equal to $50/ton of carbon. The emission reduction is expressed in Tg or in percent of baseline emissions. By summing across the sources, total potential emissions reductions are estimated for all the sources analyzed.

  This analysis focuses on the amount of emissions reductions that would be profitable at certain emissions reduction values and energy prices without considering the impact of certain barriers on the penetration of the emissions reduction technologies. Barriers such as lack of information or inadequate access to capital will slow the rate at which profitable options are adopted. The estimates presented in this report; therefore, represent the potential to reduce emissions profitably, and do not reflect the time needed for the technologies and practices to penetrate into the market. Because the majority of the practices and technologies examined in this report are well known today, the delay associated with market penetration should not be significant.

Using this method, the total emission reduction is estimated for a schedule of emission reduction values from $0/ton to $200/ton of carbon equivalent. Because the value of the energy produced by the technologies and practices plays an important role in the emission reduction estimates, the analysis was repeated for a range of energy values: from 50 to 300 percent of base energy prices. The end result is estimates of emissions reductions for combinations of energy prices and emission reduction values as shown in Exhibit 2.

Exhibit 2: Format for Emission Reduction Estimates

	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	Each cell contains the emission reduction for the combination of energy price and emission reduction value											
75% of Base												
100% of Base												
125% of Base												
150% of Base												
200% of Base												
300% of Base												

1.4 Organization of this Report

The remainder of this report is organized as follows:

- *Section 2* presents the baseline emissions used in this analysis.
- *Section 3* presents a summary of the emission reduction estimates.
- *Section 4* discusses the base energy prices that are used in the analysis.
- *Sections 5 through 8* describe the estimates for each of the four emissions sources analyzed.

1.5 References

EPA (forthcoming). *United States Methane Emissions and Costs of Reductions*, Methane and Utilities Branch, Atmospheric Pollution Prevention Division, Office of Air and Radiation, U.S. Environmental Protection Agency, Washington, D.C., in preparation.

2. BASELINE METHANE EMISSIONS

Future baseline emissions are the starting point for this cost analysis. Baseline emissions represent the emissions anticipated in the absence of efforts to reduce emissions. For purposes of this analysis, the baseline emissions do not include Climate Change Action Plan (CCAP) activities that are currently underway to reduce methane emissions and emissions of other greenhouse gases in the United States.

The baselines for each of the sources were developed using recent detailed emissions inventories and projections of key factors that affect each source. Common drivers of future emissions across the sources include: human population growth; GDP per capita; and energy production and consumption. These data were taken from the Reference Case of the Annual Energy Outlook prepared by the Energy Information Administration (DOE, 1998). Source specific estimates were developed as needed, as described in EPA (forthcoming). The baseline estimates, presented in Exhibit 3, were developed as follows:

- *Landfills.* Baseline methane emissions from landfills are driven by past and anticipated future landfilling of municipal solid waste (MSW), the rate of methane production per unit of waste disposed, and the impact of the recently promulgated Landfill Rule. Historical waste disposal and landfill data are used to characterize the current landfill population and methane emissions rate. Future landfilling is estimated to remain constant into the future as increased waste generation associated with population increases is offset by continued increases in recycling and alternative disposal methods. Future landfills are estimated to be larger on average than existing landfills, continuing the trend toward a smaller number of larger landfills over time.

  The New Source Performance Standards and Emissions Guidelines (Landfill Rule), promulgated under the Clean Air Act in March 1996, require large landfills to collect and combust their landfill gas emissions. This Rule was promulgated to reduce toxic air emissions and has the benefit of also reducing methane emissions. The baseline used for this analysis reflects the emissions reductions from landfills that are required to comply with this Rule by assuming that all the landfills covered by the Rule comply. Therefore, the emissions reductions estimated in this cost analysis are *over and above* the emissions reductions achieved under the Landfill Rule. In the absence of the Landfill Rule, baseline landfill emissions would have been higher than the estimates shown in Exhibit 3.

- *Coal Mining.* Baseline methane emissions from coal mining are driven by the amount of future coal production. Using the most recent data on the rate of methane liberated from underground and surface coal mining (see Section 6), future methane liberation is estimated using projections of national coal production from DOE (1998). The methane liberated per ton of underground coal produced is multiplied by future underground coal production, and the rate for surface mined coal is multiplied by future surface coal production. Based on the latest projection from the Annual Energy Outlook (DOE, 1998), underground coal production is expected to grow at a faster rate than surface protection through 2020. However, the production mix is highly dependent on freight rates. Although underground coal seams may become gassier over time as deeper coal is mined in some basins, the coal mining baseline assumes that the rate of methane liberation per ton of coal produced remains constant. As such, this baseline may be an underestimate of future methane liberation.

  As discussed below in Section 6, some underground coal mines currently collect and use a portion of the methane liberated during mining. Except for 1990, the baseline estimates shown in this exhibit do not reflect the emissions reductions from these current methane collection activities. Similarly, the baseline estimates do not reflect the impact of the Energy Policy Act of 1992 (EPAct) on the ability to undertake these types of projects. Instead, the emission reduction that can be achieved profitably is estimated as part of the cost analysis.

- *Natural Gas Systems.* Because natural gas is comprised primarily of methane, any leaks or intentional venting from pipelines or other equipment contribute to methane emissions. Using a component specific emissions inventory as the starting point (see Section 7), future emissions are estimated based on expected changes in the size of the system (e.g., miles of pipeline and numbers of wells) and its throughput. Changes in system size are extrapolated from past trends, and future throughput is estimated based on future energy demand (DOE, 1998). Due to improvements in technologies and operating practices anticipated over time, the overall system emissions rate is expected to decline. The baseline estimates in Exhibit 3 include a 5 percent reduction in emission factors by 2020 to reflect this trend.

- *Livestock Manure Management.* Emissions are driven by the amount of manure produced, its composition and temperature, and the way the manure is managed. Managing manure using liquid or slurry systems generates significantly more methane than managing manure using dry systems. There is a trend in livestock manure management towards increasing use of confined and intensive livestock production systems, which in turn increases the likelihood that liquid-based manure management systems will be used. The future emissions estimates reflect this trend, as well as anticipated increases in the production of milk, beef, and pork. Forecasted per capita demand (USDA, 1996) was used along with forecasts of the future human population to estimate production for domestic consumption. Estimated future exports, based on extrapolation of USDA forecasts, are added to estimated total supply, which drives emissions.

Exhibit 3: Baseline Methane Emissions in the United States (Tg)

Source	1990	2000	2010	2020
Landfills	9.8	9.0	9.1	7.2
Coal Mining	4.2	4.2	4.9	5.3
Natural Gas Systems	5.7	6.2	6.6	6.8
Livestock Manure Management	2.6	3.2	3.9	4.6
Livestock Enteric Fermentation	5.7	6.2	6.4	6.6
Petroleum Systems	1.2	1.2	1.2	1.2
Other	1.3	1.4	1.3	1.3
Total	30.6	31.3	33.4	33.1

All future emissions are estimated prior to the impacts of the Climate Change Action Plan (CCAP) programs, including the Landfill Methane Outreach Program, Coalbed Methane Outreach Program, Natural Gas STAR Program, AgSTAR, and Ruminant Livestock Efficiency Program.

Future landfill emissions are estimated after the impact of the New Source Performance Standards and Emissions Guidelines (Landfill Rule), promulgated under the Clean Air Act in March 1996. The portion of the baseline emissions that would be collected and combusted at landfill gas to energy projects at landfills not covered by the Landfill Rule is incorporated into the emission reduction analysis.

Future coal mining emissions are estimated as the total amount of methane liberated from coal mining activity. The portion of the baseline emissions that would be collected and combusted in coal mine methane recovery projects is incorporated into the emission reduction analysis. The baseline estimates do not reflect the impact of the Energy Policy Act of 1992 (EPAct) on the ability to undertake these types of projects.

Future emissions from petroleum systems are held constant at 1996 levels. Other sources include: rice cultivation; wastewater treatment; energy combustion; agriculture residue burning; and other industrial sources.

Source: EPA (forthcoming).

- *Livestock Enteric Fermentation.* Methane is produced during the normal digestive process of livestock. Ruminant animals (cattle, sheep, and goats) are the principal source of emissions due to their unique digestive systems which promote fermentation. Using a detailed emissions inventory as the starting point (EPA, 1993), future emissions are estimated based on expected changes in the production of milk, beef, and other livestock products. These estimates of future production are coordinated with the manure management system estimates discussed above. Additionally, the trend in increased production efficiency in the milk sector in the U.S. is reflected in the baseline estimates (annual milk production per milking cow increases by 300 pounds per year).

- *Petroleum Systems*. Because natural gas is commonly found with oil, petroleum production and storage equipment is a source of methane emissions. The primary sources of emissions are production field equipment, gas venting, and crude oil storage tanks. Exhibit 3 presents a recently developed revised estimate of emissions from petroleum systems that is higher than previous estimates. Trends in emissions are currently being developed, and for purposes of this analysis these emissions are held constant.
- *Other Sources.* Other sources include: rice cultivation; wastewater treatment; energy combustion; agriculture residue burning; and other industrial sources. These emissions are expected to be relatively constant over time.

As shown in the exhibit, total emissions are expected to increase through 2010, and then remain relatively constant for a period due to reductions in future landfill emissions. Due to uncertainties in the factors that drive current and future emissions, these emissions estimates remain uncertain. Sensitivity analysis is ongoing to quantify the uncertainty. The estimates presented here are the “middle” estimates for all sources (EPA, forthcoming).

2.1 References

DOE, 1998. *Annual Energy Outlook (AEO) 1998*. Reference Case Forecast, Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EPA, 1993. *Anthropogenic Methane Emissions in the United States: Estimates for 1990*, K.B. Hogan, ed., Office of Air and Radiation, U.S. Environmental Protection Agency, Washington, D.C., EPA 430-R-93-003.

EPA (forthcoming). *United States Methane Emissions and Costs of Reductions*, Methane and Utilities Branch, Atmospheric Pollution Prevention Division, Office of Air and Radiation, U.S. Environmental Protection Agency, Washington, D.C., in preparation.

USDA, 1996. *Long-term Agricultural Projections*, Economic Research Service, U.S. Department of Agriculture, Washington, D.C.

3. Summary Results

Total emissions reductions estimated for the four sources analyzed are presented in Exhibit 4 for the years 2000, 2010, and 2020. The estimates for the base energy prices are highlighted. As shown in the exhibit, emissions reductions generally increase at higher energy prices and emission reduction values. At higher energy prices, the increased value of the energy derived from the methane recovered offsets the costs of the more costly emission reduction technologies and practices so that more emissions are reduced. Similarly, at the higher emission reduction values, more costly options can be undertaken. The emission reduction estimates for 2020 are lower than the estimates for 2010 because the baseline emissions from landfills (after the Landfill Rule) decline in that year. Consequently, the emissions reductions are from a lower baseline. Exhibit 5 shows the summary results for 2010 in graphical form.

Exhibit 4: Summary Emissions Reductions: 2000, 2010 and 2020 (Tg)

Year 2000	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	5.2	6.5	7.0	8.9	9.2	9.7	10.8	11.6	11.8	11.9	12.0	12.0
75% of Base	5.9	7.0	7.3	9.2	9.7	10.1	11.5	11.7	11.9	11.9	12.0	12.0
100% of Base	**6.8**	**7.4**	**7.7**	**9.7**	**10.0**	**10.5**	**11.6**	**11.8**	**11.9**	**12.0**	**12.0**	**12.1**
125% of Base	7.3	7.6	8.2	9.9	10.4	10.8	11.6	11.8	11.9	12.0	12.0	12.1
150% of Base	7.6	8.1	10.0	10.3	10.7	11.1	11.7	11.8	11.9	12.0	12.1	12.1
200% of Base	8.5	8.7	10.6	10.8	11.1	11.6	11.8	11.9	12.0	12.1	12.1	12.1
300% of Base	10.9	11.0	11.1	11.5	11.6	11.8	11.9	12.0	12.1	12.1	12.1	12.1

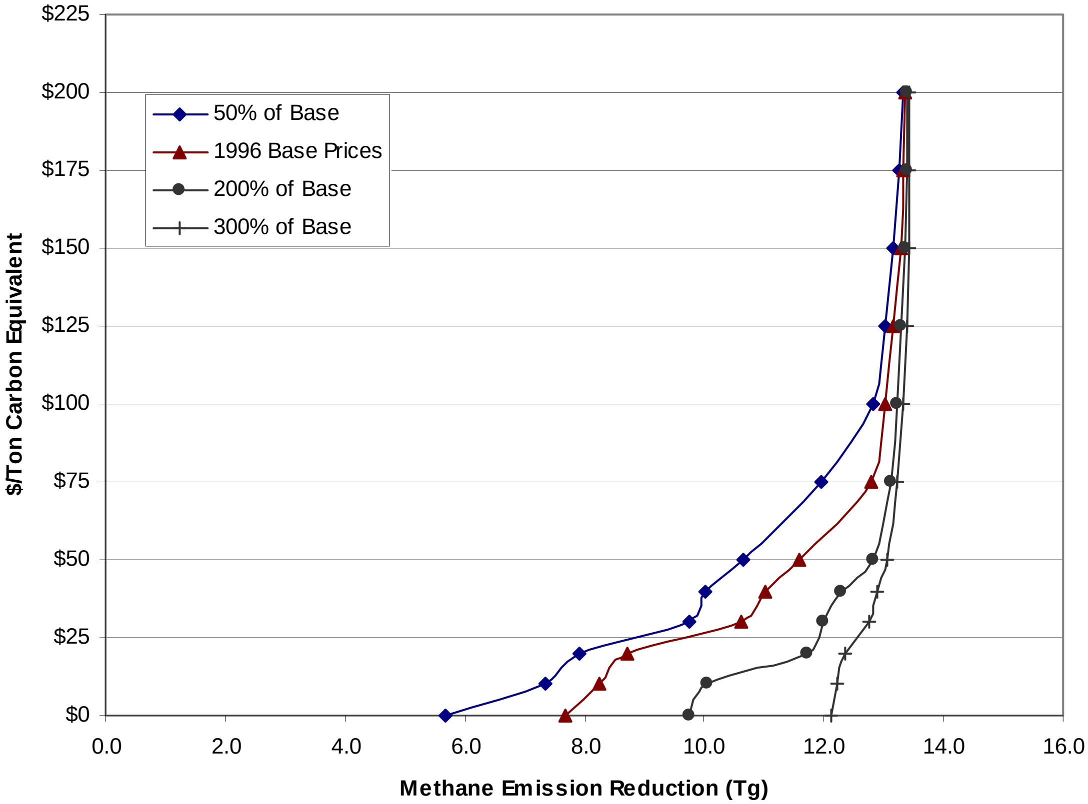
Year 2010	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	5.7	7.4	7.9	9.7	10.0	10.6	11.9	12.8	13.0	13.2	13.2	13.3
75% of Base	6.8	7.8	8.3	10.0	10.6	11.1	12.7	12.9	13.1	13.2	13.3	13.3
100% of Base	**7.7**	**8.2**	**8.7**	**10.6**	**11.0**	**11.6**	**12.8**	**13.0**	**13.2**	**13.3**	**13.3**	**13.3**
125% of Base	8.2	8.6	9.3	11.0	11.4	11.9	12.9	13.1	13.2	13.3	13.3	13.4
150% of Base	8.6	9.3	11.0	11.4	11.8	12.3	13.0	13.1	13.2	13.3	13.3	13.4
200% of Base	9.7	10.0	11.7	12.0	12.3	12.8	13.1	13.2	13.3	13.4	13.4	13.4
300% of Base	12.1	12.2	12.4	12.7	12.9	13.0	13.2	13.3	13.4	13.4	13.4	13.4

Year 2020	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	5.3	6.9	7.4	9.2	9.5	10.2	11.6	12.6	12.9	13.0	13.1	13.2
75% of Base	6.4	7.3	7.8	9.5	10.2	10.7	12.5	12.8	13.0	13.0	13.2	13.2
100% of Base	**7.2**	**7.9**	**8.3**	**10.2**	**10.6**	**11.3**	**12.6**	**12.9**	**13.0**	**13.1**	**13.2**	**13.2**
125% of Base	7.7	8.2	8.9	10.6	11.1	11.7	12.7	12.9	13.1	13.2	13.2	13.3
150% of Base	8.2	8.9	10.6	11.1	11.6	12.1	12.8	13.0	13.1	13.2	13.2	13.3
200% of Base	9.5	9.8	11.5	11.8	12.1	12.7	13.0	13.1	13.2	13.2	13.3	13.3
300% of Base	11.9	12.0	12.2	12.6	12.7	12.9	13.1	13.2	13.3	13.3	13.3	13.3

Baseline Methane Emissions: 2000 = 31.6 Tg; 2010 = 33.7 Tg; 2020 = 33.4 Tg.

Exhibit 5: Summary Emission Reduction Estimates for 2010 (Tg)

(Estimates for Four Energy Price Cases – Baseline Emissions = 33.7 Tg)



As shown in the graph, substantial reductions are achievable at costs up to $100/ton of carbon. Above $100/ton the exhibit shows that there is little opportunity to reduce emissions further. It should be noted, however, that for all four sources the analysis focuses on technologies and practices that are currently available. At higher costs it is likely that additional options, which have yet to be identified, will become available. By omitting these potential future higher-cost options, this analysis under-estimates the ability to reduce emissions at higher levels of costs.

Of the four sources, landfills contribute most to the emissions reductions. Exhibit 6 lists the portion of the total emissions reductions in 2010 associated with each source. As shown in the exhibit, landfills account for about one-third to one-half of the total emissions reductions. Livestock manure contributes up to about one-fifth of the reductions, primarily at higher energy prices and emission reduction values. Coal mining and natural gas systems account for about one-quarter each.

The results for each of the sources are presented in more detail in the later sections of this report. Several key aspects of the analysis are as follows:

- The methane recovery efficiency at landfills is estimated at 75 percent for all landfills and is assumed to remain constant. Using the recovered methane directly in boilers or similar equipment is more cost effective than producing electricity in most cases.
- The coal mine methane analysis includes a catalytic oxidation technology for recovering heat energy from the low concentration of methane in coal mine ventilation air. This technology becomes profitable at approximately $30/ton of carbon equivalent, leading to substantial emissions reductions from underground mining. Below this emission reduction value, methane recovery is the primary method of reducing emissions. The technologies for recovering methane from coal seams are estimated to improve by 10 percent by 2020 as part of the analysis.

Exhibit 6: Portion of Emission Reduction from Each Source in 2010 (%)

Landfills	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	52%	46%	47%	38%	38%	36%	32%	30%	30%	29%	29%	29%
75% of Base	46%	47%	45%	38%	36%	34%	30%	30%	29%	29%	29%	29%
100% of Base	**47%**	**45%**	**43%**	**36%**	**35%**	**33%**	**30%**	**30%**	**29%**	**29%**	**29%**	**29%**
125% of Base	45%	44%	41%	35%	33%	32%	30%	29%	29%	29%	29%	29%
150% of Base	44%	41%	35%	34%	32%	31%	30%	29%	29%	29%	29%	29%
200% of Base	39%	38%	33%	32%	31%	30%	29%	29%	29%	29%	29%	29%
300% of Base	32%	31%	31%	30%	30%	29%	29%	29%	29%	29%	29%	29%

Coal Mining	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	18%	24%	24%	37%	36%	34%	30%	28%	27%	27%	27%	27%
75% of Base	23%	24%	25%	36%	34%	32%	28%	28%	27%	27%	27%	27%
100% of Base	**23%**	**24%**	**25%**	**34%**	**32%**	**31%**	**28%**	**27%**	**27%**	**27%**	**27%**	**27%**
125% of Base	23%	24%	24%	33%	31%	30%	28%	27%	27%	27%	27%	27%
150% of Base	23%	24%	33%	31%	30%	29%	28%	27%	27%	27%	27%	27%
200% of Base	23%	23%	31%	30%	29%	28%	27%	27%	27%	27%	27%	27%
300% of Base	30%	29%	29%	28%	28%	27%	27%	27%	27%	27%	27%	27%

Natural Gas	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	27%	26%	26%	22%	22%	22%	24%	24%	24%	24%	25%	25%
75% of Base	27%	26%	25%	21%	21%	21%	24%	24%	24%	24%	25%	24%
100% of Base	**25%**	**25%**	**25%**	**20%**	**20%**	**21%**	**24%**	**24%**	**24%**	**25%**	**24%**	**24%**
125% of Base	25%	24%	23%	20%	20%	21%	24%	24%	24%	25%	24%	24%
150% of Base	24%	23%	20%	20%	20%	21%	24%	24%	24%	24%	24%	24%
200% of Base	22%	21%	19%	19%	20%	23%	24%	24%	24%	24%	24%	24%
300% of Base	18%	19%	19%	21%	22%	23%	24%	24%	24%	24%	24%	24%

Manure	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	4%	3%	3%	3%	4%	8%	14%	18%	19%	19%	19%	20%
75% of Base	3%	3%	5%	5%	10%	12%	18%	19%	19%	19%	20%	20%
100% of Base	**5%**	**6%**	**7%**	**10%**	**13%**	**15%**	**18%**	**19%**	**19%**	**20%**	**20%**	**20%**
125% of Base	6%	8%	12%	13%	15%	17%	19%	19%	20%	20%	20%	20%
150% of Base	8%	12%	13%	15%	17%	19%	19%	20%	20%	20%	20%	20%
200% of Base	16%	18%	18%	19%	20%	19%	20%	20%	20%	20%	20%	20%
300% of Base	20%	21%	21%	20%	20%	20%	20%	20%	20%	20%	20%	20%

- Because the sources of methane emissions from the natural gas system are varied and diverse, a large number of technologies and practices were evaluated. Among the options evaluated, replacing high-bleed pneumatic devices and techniques for reducing emissions from compressor stations are among the most significant in terms of cost effective emission reduction.
- The principal methods for reducing methane emissions from livestock manure are to collect and combust the methane that would otherwise be emitted from liquid manure management systems. Anaerobic digester technologies (ADTs), the principal technology evaluated, produces multiple benefits, including reducing odor at swine farms as well as producing energy for on-farm use.

The results in Exhibit 4 can be used to estimate the emissions reductions that can be achieved at various carbon values and energy prices. For example, using a detailed costing and energy model, one may be estimating the costs of achieving a certain level of greenhouse gas emissions in a specific year, such as 2010. Within this model, the impact on energy prices will be estimated, along with the marginal cost of reducing emissions from their various sources. The data in Exhibit 4 provide the basis for estimating the methane emissions reductions by selecting from the appropriate table the emission reduction corresponding to the energy price simulated for that year and the marginal emission reduction cost. For example, if real energy prices are simulated to be 50 percent higher and the marginal cost of reducing emissions overall in the model is $40/ton of carbon in 2010, then methane emissions could be reduced by about 11.8 Tg from the baseline values using the technologies and practices evaluated in this analysis.

4. Base Energy Prices

Because nearly all of the technologies and practices for reducing methane emissions from landfills, coal mining, natural gas systems and livestock manure produce or save energy, energy prices are a key driver of the cost analyses. The value of the energy produced or saved offsets to various degrees the capital and operating costs of reducing the emissions. Higher energy prices offset a larger portion of these costs, and in some cases make the technologies and practices profitable.

Given the importance of energy prices in the analysis, the analysis is performed for a base set of prices and for six additional cases of lower and higher prices. The cases are expressed as percentages of the base prices, and vary from 50 to 300 percent of the 1996 base prices. The base energy prices adopted for this analysis are as follows:

- *Landfills:* Landfills can produce electricity or sell gas directly to nearby customers. Therefore, both electricity and gas prices are needed.

  The electricity price needed is the rate at which landfills could sell electricity to the local distribution company. No single published price represents this value, which depends on local conditions and potentially the demand for renewable power. A base value of $0.04/kWh is used as representative to reflect the value of the energy produced, the proximity of landfills to population centers (thereby avoiding transmission costs), and a premium for renewable energy.

  The gas price needed is a value that represents what the landfill could sell gas for to a nearby customer. The average industrial gas consumer price is most representative. However, in this analysis the price is discounted because landfill gas is a medium quality gas whose supply may be less certain than the gas supplied by the local distribution system. Consequently, $2.736/MMBtu is used, which is 20 percent below the observed average industrial price (DOE, 1997b).

- *Coal Mining:* The methane recovered at coal mines can be injected directly into the natural gas pipeline system for sale, can be used on-site for energy, or can be used to produce electricity. To analyze the pipeline sale option (see Section 6), a gas price is needed that represents what the coal mine could sell gas for as it injects it into a pipeline. The average wellhead gas price in the relevant coal mining states is most appropriate because the coal mine is providing gas of a similar quality as a gas field. The average wellhead price in 1996 for Alabama; Indiana; Kentucky; and Ohio was $2.525/MMBtu (DOE, 1997b). Although data are not available for other coal mining states (West Virginia; Virginia; Pennsylvania; and Illinois), the wellhead prices in these states are expected to be similar to the average value used in the analysis because prices are heavily influenced by location along the gas transmission system.

  To analyze the catalytic oxidizer option, which produces heat that can be used to produce electricity on-site, an electricity price is needed that reflects the value of using the electricity on-site or selling it to the grid. Based on discussions with mine operators, electricity rates are on the order of $0.03/kWh. This is used as the base rate for the analysis. It is reasonable for this rate to be below the base rate used for the landfill analysis because landfills are typically closer to population centers[2] and the electricity produced from landfills may command a premium as a renewable energy source.

- *Natural Gas Systems:* The set of gas prices needed is the value of the gas saved by preventing leakage and venting. This value varies throughout the system, with the value being lower at the wellhead end of the system and higher at the customer end. National average gas prices for 1996 are used as follows (DOE, 1997b): wellhead gas price of $2.17/MMBtu; pipeline gas price of $2.27/MMBtu; and city gate gas price of $3.27/MMBtu.

- *Livestock Manure:* The methane produced from livestock manure can be used to produce electricity for on-site use. Consequently, the electricity price needed is the rate at which farmers could displace their on-farm electricity costs. The closest published rates are commercial electricity prices which

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[2] Being located close to population centers reduces transmission costs, thereby providing an opportunity to recover a higher price for the energy produced.

vary by state (DOE, 1997a). However, these prices are higher than the cost savings that can typically be achieved by farmers due to connect charges and demand charges that are part of their electricity rates. Therefore, this analysis uses electricity prices $0.02/kWh less that the published state averages.

Exhibit 7 lists the base energy prices used in the analysis.

To analyze how placing a value on reducing emissions would affect the profitability of emission reduction technologies and practices, the emission reduction values were translated into energy prices for each of the sources analyzed. As discussed below, the emission reduction values were translated into equivalent electricity and gas prices using the heat rate of the engine-generator (for electricity), the energy value of methane (1,000 Btu/cubic foot), and a global warming potential (GWP) of 21 (IPCC, 1996). Exhibit 8 displays the equivalent energy prices for the emission reduction values examined.

Exhibit 7: Base 1996 Energy Prices Used in the Analysis

Methane Source	Electricity Price	Gas Price
Landfills	$0.04/kWh	$2.736/MMBtu
Coal Mining	$0.03/kWh	$2.525/MMBtu
Natural Gas Systems	NA	Wellhead: $2.17/MMBtu Pipeline: $2.27/MMBtu City Gate: $3.27/MMBtu
Livestock Manure Management	$0.02/kWh below the state average commercial electricity price	NA
Sources: See Text		

Exhibit 8: Equivalent Electricity and Gas Prices by Source

	Emission Reduction Value ($/ton of Carbon Equivalent)											
Source	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
Electricity Prices ($/kWh)												
Landfills	$0.000	$0.013	$0.027	$0.040	$0.054	$0.067	$0.101	$0.134	$0.168	$0.201	$0.235	$0.268
Manure	$0.000	$0.015	$0.031	$0.046	$0.062	$0.077	$0.115	$0.154	$0.192	$0.231	$0.269	$0.308
Gas Prices ($/MMBtu)												
All Sources	$0.00	$1.10	$2.20	$3.30	$4.40	$5.50	$8.25	$11.00	$13.75	$16.49	$19.24	$21.99
Landfill engine generator estimated to have a heat rate of 12,189 Btu/kWh.												
Manure management systems engine generator estimated to have a heat rate of 14,000 Btu/kWh.												

4.1 References

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DOE, 1997b. *Natural Gas Annual 1996*, Office of Oil and Gas, Energy Information Administration, U.S. Department of Energy, Washington, D.C., DOE/EIA-0540(96), September 1997.

IPCC (1996). *Climate Change 1995: The Science of Climate--Contribution of Working Group I to the Second Assessment of the IPCC*, Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge (UK).

5. U.S. Cost Analysis: Methane Emissions from Landfills

Landfills are the largest anthropogenic source of methane emissions in the United States. While the recently promulgated Landfill Rule is reducing emissions from the larger US landfills, there are still technically feasible and cost effective reductions at smaller landfills not covered by this regulation. This cost analysis estimates the amount of landfill methane emissions that can be reduced at a profit for a range of energy prices and emission reduction values expressed in $/ton of carbon equivalent through the year 2020. The two emissions reductions technologies examined are recovering landfill gas and producing electricity and recovering landfill gas and using it directly in boilers and other equipment. Other gas use options are available, but tend to be more costly. The cost of recovering and using the gas is offset to various extents by the value of the energy produced, so that some projects are profitable in their own right. The option of collecting and flaring landfill gas was also examined, but using the gas for energy was typically more cost effective than flaring at current energy prices so flaring is not included in the cost curve results.

5.1 Source Summary

Methane is produced and emitted through the anaerobic decomposition of organic material in landfills. Emissions are driven by the amount of organic material deposited in landfills, the extent to which the deposited material decomposes anaerobically, and the extent to which landfill methane is collected and combusted (e.g., used for energy or flared). Because it takes many years for organic material to break down completely in landfills, the emissions today are driven by past landfill disposal practices.

In this analysis, future methane emissions are estimated by simulating the disposal of waste in a population of landfills. Landfill population simulation accounts for large and medium landfills but does not include small or industrial landfills. Excluding the small and industrial landfills, approximately 2,900 landfills are simulated in the U.S. landfill population.

Emissions for small landfills are based on an estimate of the portion of total waste that is disposed in small landfills. This portion is estimated to decline over time, so that methane emissions from small landfills are estimated to decline from 12 percent of current emissions to 4 percent of the total emissions by 2020. Industrial landfill emissions are assumed to be 7% percent of the total emissions.

5.2 Scope of Emissions Reductions

Options Included in the Analysis: The cost analysis focuses on technologies for recovering and using landfill methane for energy. The landfill methane is withdrawn using wells drilled into the waste. Negative pressure is applied to the wells to withdraw the gas. Once withdrawn, the gas is used in one of two ways:

- produce electricity using an internal combustion (IC) engine-generator; or
- dry and compress the gas for sale as a medium quality gas (e.g., 500 Btu/cubic foot) to a nearby customer for use in a boiler or other equipment.

Collecting and using landfill gas for energy is an increasingly common practice. Today, more than 150 landfills currently collect and utilize their gas for energy, while hundreds more collect and flare their gas to meet gas migration abatement requirements (EPA, 1997a).[3] The analysis is based on data from existing gas recovery projects and from discussions with experts who design and build landfill gas recovery projects.

Options Not Included in the Analysis: Techniques for reducing emissions that are not included in the cost analysis are:

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[3] Gas is flared rather than used for energy when the amount of gas produced is small or the rate of production is highly variable. Gas migration abatement typically involves perimeter wells that collect only a portion of the gas produced in a landfill. Although flaring can be a preferred option under these conditions, this cost analysis focuses on collecting methane from entire landfills such that gas use will typically be preferred to flaring.

- Reduce Landfilling: Reducing landfilling of organic material will reduce the potential for future emissions. Landfilling can be reduced through recycling, waste minimization, and waste diversion to alternative treatment and disposal methods, such as composting and incineration. Significant efforts are underway in the U.S. at both the federal and state levels to reduce landfilling. The anticipated impacts of these efforts are included in the baseline methane emissions estimates, and consequently are not included in the cost analysis.
- Additional Gas Uses: Landfill gas can be used in several additional ways, including:
  - Turbine generators can be used to generate electricity. While turbines are often best for large projects (in excess of 3 megaWatts (MW)), IC engines are more cost effective for the sizes of projects examined in this analysis. Because the 300-350 largest landfills in the U.S. are expected to recover and combust their gas under the new Landfill Rule (see below), this analysis focuses on the smaller landfills for which IC engines will be preferred.
  - Landfill gas can be processed and cleaned to meet the standards of the natural gas pipeline system (e.g., as a high quality 1,000 Btu/cubic foot gas). Once processed in this manner the gas can be sold through the existing natural gas pipeline system. This option may be appropriate in limited cases, such as when very large quantities of gas are available. This option is excluded from this analysis due to its relatively high costs compared to the other options examined.
  - Landfill gas can be processed into liquid vehicle fuel which can be used to fuel the fleet of trucks hauling refuse to a landfill. However, it is currently more costly than the other options examined and consequently is omitted from this analysis.
  - Landfill gas can be flared. Flaring may be the most cost effective option for reducing emissions at landfills that cannot support an electric generator system or sell the gas to a nearby customer. Initial analysis of gas collection and flaring indicates that flaring is more cost effective than electricity generation and direct gas use at various levels of emission reduction values only when the energy price is very low (e.g., less than $0.02/kiloWatt-hour (kWh)). At higher energy prices (e.g., $0.04/kWh) electricity generation is preferred to flaring at all levels of emission reduction values. In this respect, flaring becomes a backstop technology to electricity generation and direct gas use when energy prices are very low.

Each of these technologies has been used at U.S. landfills. As discussed above, this analysis focuses on IC electric generators and direct gas sales because these are the most cost effective technologies for the sizes of landfills that would be affected by placing a value on GHG emissions reductions.

Interactions with Other Trends or Events Affecting Emissions: The New Source Performance Standards and Emissions Guidelines (Landfill Rule), promulgated under the Clean Air Act in March 1996, require large landfills to collect and combust their landfill gas emissions. This analysis includes estimating the emissions reductions from landfills that are required to comply with this Rule and assumes that all the landfills comply. By taking these emissions reductions into account, the Landfill Rule is reflected in the emissions baseline. Therefore, the emissions reductions estimated in this cost analysis are *over and above* the emissions reductions achieved under the Landfill Rule. Other state and local requirements to prevent off-site migration of landfill gas or reduce odor are assumed not to be significant in terms of emissions reductions and costs.

Because the cost analysis focuses on using landfill gas for energy, energy prices influence the estimates. Higher electricity or gas prices will make landfill gas recovery and use more economically attractive and more projects will be undertaken. Given the ongoing restructuring of the electric power industry, there is the potential that electricity derived from landfill gas could command a price premium as a renewable energy source, thereby increasing the attractiveness of electricity generation at landfills.

5.3 Methodology

The cost analysis is performed across a population of existing and anticipated new landfills. First the landfill population analysis is presented, followed by a discussion of the cost analysis performed for each landfill. Both electricity production and direct gas use are analyzed for each landfill. Direct gas use is typically more profitable, particularly if a customer for the gas can be induced to locate on-site, thereby avoiding the need to build and operate a pipeline to deliver the gas. For purposes of this analysis, the choice of which option is best at a given landfill does not affect the emission reduction estimate because both options reduce emissions the same amount at a landfill, 75 percent. A summary table of the data and assumptions used in the analysis is attached at the end of this section.

- ***Landfill Population Analysis:*** To conduct this analysis, the current and expected future population of landfills is required. Each landfill is characterized in terms of its time of opening, waste acceptance during its operation, and time of closing. To characterize the population of landfills as of 1990, the analysis begins with EPA's landfill survey (EPA 1988). The future population of landfills was estimated by:

  - projecting the amount of waste disposed in landfills over time nationally;
  - simulating the disposal of the waste in the existing landfills over time as their design capacity and acceptance rates allow;
  - simulating the closure of existing landfills as they reach their design capacity; and
  - simulating the opening of new landfills when a significant shortfall in disposal capacity is estimated to occur.

  The rate of future landfilling is uncertain. Whereas waste generation may increase with increased population, continued increases in recycling, alternative disposal methods, and source reduction may limit future landfilling. Alternatively, if landfilling prices decline, the landfill industry may recapture market share, leading to increased landfilling. This analysis assumes that the amount of waste landfilled remains constant at the 1990-1995 average. If the amount of waste landfilled increases (decreases), emissions will be higher (lower) than the estimates used here.

  When new landfills are simulated to be opened, they are assumed to be larger, on average, than the landfills they are replacing, reflecting the trend toward a smaller number of regional waste disposal facilities. The end result of this process is a simulated population of landfills over time that includes the information needed to conduct the cost analysis.

- ***Landfill Rule:*** Prior to examining the opportunity to collect and use landfill gas at each landfill, the impact of the Landfill Rule is analyzed.

  - Gas Generation: The amount of landfill gas generated at the landfill over time is estimated using the methane generation model in EPA (1993). This model is driven by the amount and age of the waste in the landfill.
  - Landfill Rule: Based on the methane generated, the analysis assesses the applicability of the Landfill Rule for each landfill. If the Landfill Rule applies to the landfill, then the emission reduction at the landfill is assumed to take place as the result of the Rule. Only landfills whose emissions are below the Rule threshold are analyzed for purposes of the cost curve. In the analysis the landfills with the highest emissions are estimated to be covered by the Rule. The model is calibrated so that approximately 350 existing landfills and 50 new landfills will be covered by the Rule by the year 2000. As mentioned above, it is assumed that all the landfills covered by the Rule comply by collecting and combusting their gas.

- ***Electricity Production Cost Analysis:*** The cost analysis is performed by examining each of the landfills not triggered under the Rule in the landfill population to assess whether and to what extent it is profitable to collect and use its landfill gas. The following steps were performed to analyze the electricity production option:

  - System Components and their Costs: Each gas-to-electricity project will include a collection system, flare system, and electricity production system. The original cost and performance data for these systems were presented in EPA (1991a), EPA (1991b), and EPA (1992). The cost data were reviewed and updated in EPA (1996) and subsequently used as the starting point for developing the cost factors in EPA’s Energy Project Landfill Gas Utilization Software, E-Plus (EPA, 1997b). These costs include design, permitting, capital, and operating costs. The individual system components are as follows.

- Collection System: All gas recovery projects start with a gas collection system, which typically includes wells drilled into the waste, blowers to apply negative pressure to the wells, simple gas dewatering and filtering, and piping to connect the components. Exhibit 9 lists the factors used to estimate the collection system capital and operating and maintenance (O&M) costs (exhibits are presented at the end of the section, starting on page 20). As shown in the exhibit, these costs are driven primarily by the amount of waste in place. The gas collection efficiency is assumed to be 75%.

- Flare System: All gas recovery projects require a flare system. Exhibit 9 lists the factors used to estimate the flare system capital and O&M costs. As shown in the exhibit, these costs are driven primarily by the peak gas flow from the collection system, which itself is driven by the amount of waste in place that is producing gas.

- Electricity Production: Electricity production requires a variety of equipment, including: compressors to move the gas; a prime mover (IC engines in this case); electric generator; an interconnect with the local electric grid; and a monitoring and control system. This analysis estimates the capital and O&M costs of this system using the aggregate factors listed in Exhibit 9.

The total costs are estimated as the sum of the components listed above. Exhibit 10 lists estimated costs for projects of various sizes as defined by the electricity production capacity in MW. As shown in the exhibit, the electric system capital costs are about 2 to 3.5 times the capital cost of the collection system. Total capital costs range from about $1,550/kW to nearly $2,000/kW for projects in this size range of 0.5 to 5.0 MW. These estimates were verified through comparison with the latest data in E-PLUS, EPA-distributed software used to evaluate the profitability and feasibility of landfill gas to energy projects (EPA, 1997b).

- Revenue: The revenue from the project is estimated for a range of values for the electricity produced and the emissions reductions achieved. The rate at which electricity can be sold from a landfill project depends on local and regional electric power market conditions, and often varies by time of day and season of year. For purposes of this analysis, a base price of $0.04/kWh was taken as a representative figure. The annual total kWh production from the project is estimated based on the amount of gas produced and collected each year.

  The value of the emission reduction is estimated by converting the emissions value in $/ton of carbon equivalent into $/ton of methane using a Global Warming Potential (GWP) of 21. For modeling purposes, this methane value was converted into an equivalent electricity rate using the heat rate of the engine-generator, 12,189 Btu/kWh.

- Profitability: The profitability of implementing a project at each landfill is assessed using a discounted cash flow analysis using the above costs and revenues along with the following parameters: real discount rate of 8 percent; depreciation period of 10 years; and marginal tax rate of 40 percent. The possible starting dates for the project are varied from the later of 1990 and the open year of the landfill to the closing year of the landfill. Electricity production is assumed to take place for 20 years, with an option at the end of the 20 years to replace the engines and generate electricity for another 20 years. The starting date and project duration with the highest net present value (NPV) is identified as the preferred project, and if the NPV is positive the project is profitable.

  A 20 year period is used for the NPV analysis reflecting the expected life of the generating equipment. Given the expected availability of the electric power system to take the power, a long time horizon is reasonable.

- ***Direct Gas Sales Analysis:*** Current efforts under EPA's Landfill Methane Outreach Program (LMOP) indicate that direct gas sales is a particularly attractive option for many landfills. For landfills that in any given year of the analysis are not triggered by the Rule, the analysis examines the profitability of gas sales directly to a nearby customer using E-PLUS as follows.

  - "Model" Direct Gas Use Project: A "model" direct gas use project was defined in E-PLUS to include the following components:

- gas collection and flare system;
- gas treatment, including dehydration and filtering;
- gas compression to 50 psi; and
- a one mile gas pipeline to the customer.

- Break-Even Gas Prices: For a range of landfill sizes (measured in terms of waste in place, WIP), the break-even gas price required to support a model direct gas use project was estimated using E-PLUS. For each landfill size E-PLUS determines the sizes and costs of each of the system components. The break-even gas price is the price required per MMBtu to produce a zero net present value (NPV) over the 15 year life of the project. The financial assumptions in the analysis of the break-even gas prices were: 8% real discount rate; 40% marginal tax rate; and straight-line depreciation over 10 years. Exhibit 11 lists the cost estimates and the break-even gas prices. As shown in the exhibit, as the size of the landfill increases, the break-even gas price declines.

  A 15 year project lifetime, the standard E-Plus value, is used for this analysis. Because a direct gas use project typically depends on a single customer, a project lifetime that is shorter than the electricity option may be appropriate.

- Define Gas Prices: As discussed above, the electricity production analysis was performed for a series of electricity prices that reflect alternative electricity prices and emission reduction values. Gas prices that reflect the value of emissions reductions were paired to these electricity prices as shown in Exhibit 12. The base gas price, which was paired with the base electricity price of $0.04/kWh, is $2.736/MMBtu. This base price is 80% of the national average industrial natural gas price of $3.42/MMBtu (DOE, 1997). The industrial gas price is discounted by 20% to account for the fact that the landfill gas is a medium Btu gas. Gas prices were paired with the other electricity values in Exhibit 12 based on the emission reduction value ($/ton of carbon) and the energy price case (e.g., 150 percent of the base energy price). For example, 150 percent of the base electricity price, $0.06/kWh, is paired with 150 percent of the base gas price, $4.104/MMBtu. Similarly, 125 percent of the base electricity price plus $30/ton of carbon equivalent, $0.09/kWh, is paired with 125 percent of the base gas price plus $30/ton, or $6.719/MMBtu.

- Profitable Direct Gas Use Projects: For each gas price in Exhibit 12, the breakeven WIP was calculated by interpolation from the data in Exhibit 11. This break-even WIP (also shown in Exhibit 12) was used to identify those landfills in each electricity analysis that could potentially implement a direct gas use project profitably. At each electricity price, the direct gas use projects are those landfills that: do not trigger under the Rule; do not find electricity production to be profitable; and have WIP that exceeds the break-even WIP for that electricity price/gas price pair. All landfills that meet these criteria are assumed to be able to implement a direct gas use project.

- Emissions Reductions: The emission reduction from the direct gas use projects is the gas that is collected and combusted. The emissions reductions start when the landfill exceeds the break-even WIP. As with the electricity analysis, the collection system efficiency is 75%. As the energy prices increase, the number of direct use candidate landfills increases because the break-even WIP declines, so that smaller landfills find that they can do a direct gas use project.

The end result of this cost analysis is an assessment of the profitability of using the gas (and thereby reducing methane emissions) at each of the landfills in the landfill population. Although the analysis first examines the electricity option, and then the direct gas use option, the emission reduction estimates are not affected by the order in which the options are analyzed. Each landfill is examined for both electricity and direct gas use, and if either is found to be profitable, the landfill is estimated to reduce its emissions profitably.

By summing across all the landfills the following is estimated: baseline emissions; the emissions reductions from the Rule; and the emissions reductions from landfills that are not triggered by the Rule but which can recover and use the methane profitably. The analysis takes place over time, so that landfills may be triggered by the Rule over time and profitable projects are simulated to be initiated over time as well.

To create the cost curve, the analysis was performed at the 25 pairs of prices listed in Exhibit 12. The cost curve was filled in by interpolating from these data for the full set of combinations of energy prices and emission reduction values examined. Exhibit 13 presents the cost curve results in terms of emission reduction in percent relative to baseline emissions after the Landfill Rule. As shown in the exhibit, emissions reductions range from about 30 to 40 percent at the energy prices and emission reduction values analyzed. Emission reduction potential in 2020 is slightly less than in the previous years because the Landfill Rule plays an increasingly large role in reducing emissions in the future because new landfills are estimated to be larger (on average) than existing landfills. Consequently, the emissions amenable to reduction over and above the impacts of the Rule decline in the future.

Direct gas use plays a dominant role in the analysis. At base energy prices and below, only direct gas use is profitable and electricity production does not contribute to emissions reductions. At the higher energy prices, both electricity production and direct gas use are profitable at many landfills. At approximately $30/ton of carbon or double current energy prices, all medium and large MSW landfills can reduce emissions profitably. Only small landfills and industrial landfills not analyzed in this analysis continue to emit methane unabated under these conditions. Total emission reduction, including the reductions from the Landfill Rule reach about 65 percent, only 10 percent below the maximum possible given the estimated recovery efficiency of 75 percent.

Exhibit 14 shows the gas and electricity prices used to estimate the emissions reductions in Exhibit 13. The conversion of the emission reduction values in $/ton of carbon to equivalent electricity and gas prices is also shown. Exhibit 15 shows the cost curve in a graphical form as emission reduction percent versus equivalent gas price. As shown in the exhibit, emissions reductions reach their maximum at around twice current energy prices. Emissions reductions beyond this point are limited by the estimated 75 percent recovery efficiency.

5.4 Limitations

The most important limitation to this analysis is that costs are estimated using aggregate cost factors and a relatively simple set of landfill characteristics. Additional data are needed to improve the basis for characterizing the landfill population and the potential to collect and use gas profitably at each landfill. The precision of the analysis is also hampered by the need to simulate the current and future population of landfills.

The prices at which landfills could sell electricity or gas are important drivers of the analysis. At higher (lower) rates, more (fewer) landfills will find it profitable to implement projects. In particular, the profitability of projects at landfills not triggered under the Rule is sensitive to energy prices.

As discussed above, efforts to reduce landfilling of organic material are included in the baseline emissions estimates. Heightened efforts, including waste management policies that go beyond existing programs to reduce landfilling may be cost effective in further reducing future methane emissions. The costs and benefits of such heightened efforts have not been included in this assessment.

5.5 References

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Exhibit 9: Landfill Gas To Energy Project Cost Factors

Cost Component	Cost Factors or Equation	Comments
Collection System Capital Cost	$[WIP\ (10^6\ tons)]^{0.8} \times 468{,}500$	The maximum amount of waste in place (WIP) during the project lifetime is used to estimate the capital cost.
Collection System O&M Costs	0.04 x Capital Cost + 49,020	
Flare System Capital Costs	Max Gas (ft^3/min) x 0.022 + 64,828	Max Gas is the peak gas flow rate from the collection system in cubic feet per minute.
Flare System O&M Costs	0.054 x Capital Cost + 3,500	
Electric System Capacity in megaWatts (MW)	$\dfrac{\text{Max Gas } (ft^3/hr) * 500\ BTU/ft^3}{12{,}189\ BTU/kWh \times 1000\ kW/MW}$	Max Gas is the peak gas flow rate from the collection system in cubic feet per hour. The heat rate of the IC engine is 12,189 BTU/kWh. The landfill gas is 50% methane, with a BTU content of 500 BTU/ft^3
Electric Generation System Capital Costs	Maximum of a) and b): a) $10^{0.903 \times \log(MW)} \times 1{,}674{,}000$ - Collection System Capital Costs or b) 1,200,000 * MW	MW is the system capacity. Collection system costs are as estimated above from the landfill WIP. Option a) developed from levelized costs and an 8% real discount rate over 20 years.
Electric Generation System O&M Costs	$0.015 per kWh	
All estimates in 1997 dollars. Sources: EPA, 1991a and 1991b.		

Exhibit 10: Example Cost Estimates by Landfill Gas To Energy Project Size

Size (MW)	Collect and Flare System		IC Engine/Generator		Total Costs/kW	
	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($/kW)	O&M ($/kW)
0.50	$321	$63	$646	$66	$1,933	$257
0.75	$420	$67	$946	$99	$1,821	$221
1.00	$512	$71	$1,240	$131	$1,752	$202
1.50	$685	$78	$1,813	$197	$1,666	$183
2.00	$847	$84	$2,400	$263	$1,624	$173
3.00	$1,013	$91	$3,606	$394	$1,539	$162
5.00	$1,788	$122	$6,000	$657	$1,558	$156
Estimates developed from cost factors and equations in Exhibit 9. All estimates are 1997 dollars.						

Exhibit 11: Direct Gas Use Cost Estimates and Break-Even Gas Prices by Landfill Waste in Place

WIP (tons 000)	Collection and Flare		Compression		Gas Treatment		Pipeline		Total		Break-Even Gas Price ($/MMBtu)
	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	
50	$95	$3.0	$2.7	$12.5	$3.24	$10.0	$185	$19	$572	$44.0	$19.23
100	$107	$4.0	$5.5	$13.1	$3.29	$10.0	$185	$19	$600	$45.6	$10.04
150	$118	$5.0	$8.2	$13.6	$3.33	$10.0	$185	$19	$628	$47.1	$6.98
200	$129	$6.0	$11.0	$14.1	$3.38	$10.0	$185	$19	$656	$48.6	$5.45
250	$141	$7.0	$13.7	$14.7	$3.42	$10.0	$185	$19	$684	$50.2	$4.53
300	$152	$8.0	$16.5	$15.2	$3.47	$10.0	$185	$19	$712	$51.7	$3.91
350	$163	$9.0	$19.2	$15.7	$3.51	$10.0	$185	$19	$740	$53.3	$3.47
400	$175	$10.0	$22.0	$16.3	$3.56	$10.0	$185	$19	$768	$54.8	$3.15
450	$186	$11.0	$24.7	$16.8	$3.60	$10.0	$185	$19	$796	$56.3	$2.89
500	$197	$12.0	$27.5	$17.3	$3.65	$10.0	$185	$19	$824	$57.9	$2.69
550	$209	$13.0	$30.2	$17.8	$3.69	$10.0	$185	$19	$852	$59.4	$2.52
600	$220	$14.0	$33.0	$18.4	$3.74	$10.0	$185	$19	$880	$60.9	$2.38
700	$243	$16.0	$38.5	$19.4	$3.83	$10.1	$185	$19	$936	$64.0	$2.16
800	$277	$19.0	$44.0	$20.5	$3.92	$10.1	$185	$19	$1,015	$68.1	$2.04
900	$299	$21.0	$49.4	$21.6	$4.01	$10.1	$185	$19	$1,071	$71.1	$1.92
1,000	$328	$23.0	$115.0	$34.3	$5.08	$10.2	$185	$19	$1,261	$85.9	$1.06

Source: Developed for model direct gas use project using E-PLUS (see text). Estimates are an average for arid and non-arid conditions.

Exhibit 12: Electricity - Gas Price - Break-Even Landfill WIP Estimates

Electricity Price ($/kWh)	Gas Price ($/MMBTU)	Break-even WIP (Tons)
$0.020	$1.368	963,205
$0.025	$1.710	922,756
$0.030	$2.052	787,589
$0.035	$2.545	543,973
$0.040	$2.736	488,699
$0.045	$3.360	367,446
$0.050	$3.420	358,080
$0.055	$4.044	289,198
$0.060	$4.104	284,335
$0.065	$4.728	239,274
$0.070	$5.351	205,207
$0.075	$5.718	191,131
$0.080	$6.035	180,759
$0.085	$6.589	162,641
$0.090	$6.719	158,403
$0.100	$7.403	143,037
$0.110	$8.349	127,604
$0.120	$8.771	120,726
$0.140	$10.824	95,743
$0.160	$11.507	92,027
$0.180	$13.721	79,980
$0.200	$15.957	67,814
$0.250	$19.682	51,176
$0.300	$24.182	50,000
$0.350	$27.847	50,000

Exhibit 13: Emission Reduction For Landfills by Year (%)
(Emission Reduction Over and Above the Landfill Rule)

2000	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	32%	37%	40%	41%	42%	42%	42%	42%	42%	42%	42%	42%
75% of Base	34%	40%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%
100% of Base	**38%**	**41%**	**41%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**
125% of Base	40%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
150% of Base	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
200% of Base	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
300% of Base	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%

2010	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	32%	37%	41%	41%	42%	42%	42%	42%	42%	42%	42%	42%
75% of Base	35%	40%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%
100% of Base	**39%**	**41%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**	**42%**
125% of Base	41%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
150% of Base	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
200% of Base	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
300% of Base	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%

2020	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	31%	35%	38%	39%	39%	39%	39%	39%	39%	40%	40%	40%
75% of Base	33%	38%	39%	39%	39%	39%	39%	39%	39%	40%	40%	40%
100% of Base	**37%**	**39%**	**39%**	**39%**	**39%**	**39%**	**39%**	**39%**	**39%**	**40%**	**40%**	**40%**
125% of Base	38%	39%	39%	39%	39%	39%	39%	39%	40%	40%	40%	40%
150% of Base	39%	39%	39%	39%	39%	39%	39%	39%	40%	40%	40%	40%
200% of Base	39%	39%	39%	39%	39%	39%	39%	40%	40%	40%	40%	40%
300% of Base	39%	39%	39%	39%	39%	39%	40%	40%	40%	40%	40%	40%

Baseline Methane Emissions: 2000 = 9.0 Tg; 2010 = 9.1 Tg; 2020 = 7.2 Tg.
See Exhibit 14 for the energy prices used in the analysis.

Exhibit 14: Electricity and Gas Prices Used in the Landfills Analysis

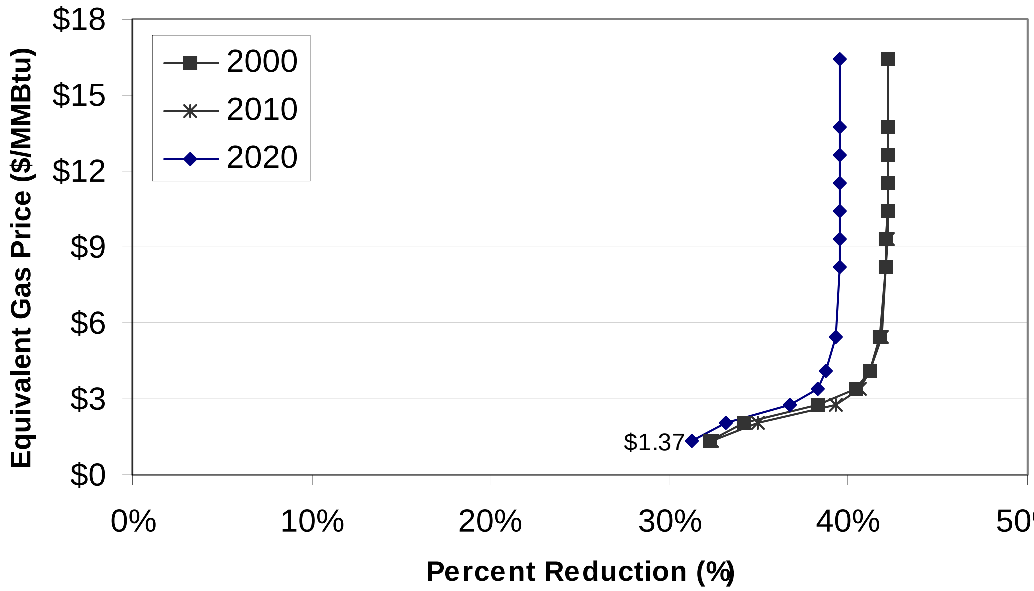
$/kWh	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	$0.020	$0.033	$0.047	$0.060	$0.074	$0.087	$0.121	$0.154	$0.188	$0.221	$0.255	$0.288
75% of Base	$0.030	$0.043	$0.057	$0.070	$0.084	$0.097	$0.131	$0.164	$0.198	$0.231	$0.265	$0.298
100% of Base	**$0.040**	**$0.053**	**$0.067**	**$0.080**	**$0.094**	**$0.107**	**$0.141**	**$0.174**	**$0.208**	**$0.241**	**$0.275**	**$0.308**
125% of Base	$0.050	$0.063	$0.077	$0.090	$0.104	$0.117	$0.151	$0.184	$0.218	$0.251	$0.285	$0.318
150% of Base	$0.060	$0.073	$0.087	$0.100	$0.114	$0.127	$0.161	$0.194	$0.228	$0.261	$0.295	$0.328
200% of Base	$0.080	$0.093	$0.107	$0.120	$0.134	$0.147	$0.181	$0.214	$0.248	$0.281	$0.315	$0.348
300% of Base	$0.120	$0.133	$0.147	$0.160	$0.174	$0.187	$0.221	$0.254	$0.288	$0.321	$0.355	$0.388

$/MMBtu	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	$1.368	$2.468	$3.567	$4.667	$5.767	$6.866	$9.615	$12.36	$15.11	$17.86	$20.61	$23.36
75% of Base	$2.052	$3.152	$4.251	$5.351	$6.451	$7.550	$10.30	$13.05	$15.80	$18.55	$21.30	$24.04
100% of Base	**$2.736**	**$3.836**	**$4.935**	**$6.035**	**$7.135**	**$8.234**	**$10.98**	**$13.73**	**$16.48**	**$19.23**	**$21.98**	**$24.739**
125% of Base	$3.420	$4.520	$5.619	$6.719	$7.819	$8.918	$11.67	$14.42	$17.16	$19.92	$22.66	$25.41
150% of Base	$4.104	$5.204	$6.303	$7.403	$8.503	$9.602	$12.35	$15.10	$17.85	$20.60	$23.35	$26.10
200% of Base	$5.472	$6.572	$7.671	$8.771	$9.871	$10.97	$13.72	$16.47	$19.22	$21.97	$24.72	$27.46
300% of Base	$8.208	$9.308	$10.41	$11.51	$12.61	$13.71	$16.46	$19.20	$21.95	$24.70	$27.45	$30.201

Equivalent	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
$/kWh	$0.000	$0.013	$0.027	$0.040	$0.054	$0.067	$0.101	$0.134	$0.168	$0.201	$0.235	$0.268
$/MMBtu	$0.000	$1.100	$2.199	$3.299	$4.399	$5.498	$8.247	$10.10	$13.74	$16.50	$19.24	$21.99

Exhibit 15: Emission Reduction Versus Equivalent Gas Price For Landfills by Year (%)

(Emission Reduction Over and Above the Landfill Rule)
Baseline Methane Emissions: 2000 = 9.0 Tg; 2010 = 9.1 Tg; 2020 = 7.2 Tg.



As shown in the exhibit, significant emission reduction can be achieved at current equivalent energy prices of $2.74/MMBtu. At approximately double the current prices, or at an emission reduction value of about $30/ton of carbon equivalent above current prices (see Exhibit 14), the maximum emission reduction is achieved. At these levels, all medium and large MSW landfills reduce emissions profitably. Only small landfills and industrial landfills not included in the analysis continue to emit methane unabated.

The percent emission reduction does not approach 75 percent because these emissions reductions are over and above the reductions achieved by the Landfill Rule. The emissions from the landfills triggered by the Rule cannot be reduced by more than the 75 percent recovery efficiency. The following example illustrates this point:

- Total emissions prior to the Landfill Rule in 2010: 14.6 Tg
- Emissions from landfills triggered by the Rule:
  - Baseline emissions: 7.4 Tg
  - Emissions after the Rule: 1.8 Tg
  - Emissions are reduced by the recovery efficiency of 75 percent
- Emissions from medium and large landfills not covered by the Rule
  - Baseline emissions: 5.1 Tg
  - Emissions after the all landfills undertake profitable projects: 1.3 Tg
  - Emissions are reduced by the recovery efficiency of 75 percent
- Emissions from small and industrial landfills:
  - Baseline emissions: 2.1 Tg
  - No emissions reductions estimated for these landfills

- Total emission reduction after the Rule:
  - Baseline emissions: 14.6 Tg - 5.6 Tg (Rule reduction) = 9.0 Tg
  - 75 percent emission reduction at medium and large landfills not triggered by the Rule: -3.8 Tg
  - Final emissions after Rule and profitable recovery = 9.0 – 3.8 = 5.2 Tg. Profitable emission reduction = 3.8/9.0 = 42 percent.

Summary of Data and Assumptions Used in the Landfill Analysis

Element of the Analysis	Current Values	Comments
U.S. Landfill Population	The 1990 landfill population is estimated based on 1988 OSW landfill survey. Post-1990 population simulated from waste acceptance rates, national disposal rates and design capacities.	Waste landfilled held constant at the average of 1990-1995 rate into the future.
Landfills that trigger under the Rule	The landfills that trigger under the Rule are estimated based on their gas production rate and NMOC concentration.	The model is calibrated so that it estimates the number of landfills expected to be triggered under the Rule: approximately 350 existing landfills and 50 new landfills by the year 2000.
Industrial Landfills	Assumed to have emissions equal to 7% of the emissions from MSW landfills (EPA, 1993).	Assumption based on an estimate of the amount of organic waste placed in industrial landfills per year as a percentage of waste in municipal landfills.
Methane Generation Rate	Methane generation in the landfill is estimated with the WIP-30 equation developed by the EPA for the 1993 Report to Congress (EPA, 1993).	
Electric Generation Project Size	The project is sized to use the peak gas flow during the project period.	Gas flow is relatively constant producing a reasonably high capacity utilization factor.
Electric Generation Project Duration	The electric project duration is 20 years. There is also an option to do back-to-back 20 year projects (for a total of 40 years).	It is assumed that to do the second 20 year project the engine-generator must be replaced, but the collection system can continue to be used.
Electric Generation Project Start Date	The starting time for the project is identified by examining all possible start times from 1990 onwards. The start time with the highest NPV is used unless the landfill is triggered by the Rule, in which case collection and combustion must start when the landfill triggers or before.	The optimal starting time affects the amount of future emissions reductions for a given year in the analysis.
Direct Gas Use	The direct gas use project assumes a one mile pipeline distance. A 15 year project time horizon is used.	
Value of Emissions Reductions	The value of emissions reductions is estimated as the gas recovered times the value ($/ton) of the gas recovered taking into account the GWP of methane (21).	

Element of the Analysis	Current Values	Comments
Discounted Cash Flow Parameter Assumptions	Real Discount Rate: 8% Tax Rate: 40% Depreciation: straight line Combustion Project Time Horizon: 20 year project or 2 back to back 20 year projects (40 years total) Direct Gas Project Time Horizon: 15 years	
Energy Prices	Ranges of electricity and gas prices are analyzed. The 1996 base electricity price is $0.04/kWh. The base gas price, $2.736/MMBtu, is 80% of the 1996 average industrial gas price. Prices are held constant over time.	The energy price is a critical driver of the analysis and the results are very sensitive to price. The current restructuring of the electric industry could lead to a premium for renewable power, which could boost the price for the landfill gas derived electricity.
Combustion Project and Gas Modeling Assumptions	Collection Efficiency: 75% Oxidation: 10% Utilization: 100% of gas collected	

6. U.S. Cost Analysis: Methane Emissions from Coal Mining

Cost curves for reducing methane emissions from coal mining focus on reducing emissions from underground mining, which accounts for about 72 percent of the emissions from this source. Two approaches are examined for reducing methane emissions from underground coal mines. The first approach is recovering the methane directly from the coal seam and its surrounding strata using degasification technologies, and injecting the methane into a natural gas pipeline for sale. The second and complementary approach is to oxidize the methane that is released in the mine ventilation air. Recently developed catalytic oxidation technology enables an oxidizer system to operate and produce thermal energy (heat) from the low concentration of methane in the ventilation air. This heat can be used for on-site energy needs or can be used to generate electricity. Emissions reductions are estimated to be the amount of methane that would otherwise have been liberated that can be profitably recovered at each of the energy prices and emission reduction values examined using these two techniques.

6.1 Source Summary

Methane is stored in coal seams and also within the strata surrounding the seams. Methane is released from both underground and surface coal mines during coal mining, and is also released directly from coal during processing, storage, and transportation (referred to as post-mining emissions). Underground coal mining is the primary source of emissions, accounting for about 72 percent of total emissions from this source. Surface mining accounts for about 11 percent, and post-mining emissions from both underground and surface mining account for the remainder. A few underground mines with very high emissions account for the vast majority of emissions in the United States. The top 125 of 573 mines in terms of methane emissions accounted for 97.8% of 1997 underground emissions (MSHA, 1998). Further, the top 25 mines in terms of methane emissions accounted for 75% of 1997 underground emissions.

Methane is emitted from underground mining either through the mine's ventilation system or through its degasification system. Because methane poses a serious safety hazard in underground mines, federal safety regulations require that methane concentrations not exceed one percent in mine workings. Ventilation systems are used to keep the methane concentration within allowable levels. Ventilation systems consist of large fans that pump air through mine workings to dilute the methane. (These fans account for about 25 percent of total mine electricity requirements.) The diluted methane, or ventilation air, is then vented to the atmosphere.

In particularly gassy mines, the ventilation system may be supplemented with a degasification system. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that recover methane before, during and after mining. At some very gassy mines, degasification systems are needed to maintain safe working conditions because the ventilation system alone cannot control methane concentrations sufficiently in the mine workings. Other mines use degasification systems because they are more economical than relying solely on the ventilation system. Methane recovered from degasification systems is not as diluted as ventilation emissions; typically degasification emissions contain 30-95 percent methane in air. Thus, the methane can be used readily as an energy source. In 1996, 21 U.S. coal mines employed degasification systems as a supplement to their ventilation systems.

6.2 Scope of Emissions Reductions

Options Included in the Analysis. The emissions reductions analysis examines recovering methane using a combination of degasification techniques and using the methane for energy. As shown in Exhibit 16, several different types of wells and boreholes can be used to withdraw methane from the coal seam and its surrounding strata, each of which is currently used to various extents in U.S. coal mines (exhibits are presented at the end of the section, starting on page 35). One advantage of using these techniques is that they produce methane that can be used for energy.

In addition to recovering and using the methane for energy, the analysis examines oxidizing the methane in the ventilation air using a catalytic oxidizer. Recently developed oxidation technology enables thermal energy (heat) to be produced from the low concentration of methane in the ventilation air. This heat can be used for on-site energy needs or can be used to generate electricity. The value of the energy produced can offset the cost of the system so that it becomes profitable. In cases where it is not practical or profitable to use the energy (e.g., under a scenario of very low energy prices), the system could be used solely as a means of reducing emissions. This analysis examines both alternatives: with and without using the heat produced by the oxidizer.

These technologies are divided into three options, which build on each other as follows (Exhibit 17):

- Option 1: Degasification and Pipeline Injection. Under this option, coal mines recover methane using: vertical wells five years in advance of mining; horizontal boreholes one year in advance of mining; and gob wells. All of the gas recovered is sold to a pipeline. Only the high quality gas produced during the early stages of production from gob wells is assumed to be sold under Option 1.

  Horizontal boreholes are drilled inside the mine to drain methane from the unmined areas of the coal seam or blocked out longwall panels shortly before mining. Boreholes are typically tens to hundreds of meters in length (EPA, 1993). Gob wells are drilled from the surface to a point 2 to 15 meters above the coal seam being mined. As mining advances under the well, the methane-charged coal and strata around the well fracture, allowing methane to flow into the gob well and to the surface. Negative pressure is applied to the gob well at the surface to prevent the methane from flowing into the mine workings (EPA, 1993).

- Option 2: Enhanced Degasification, Gas Enrichment, and Pipeline Injection. This option reflects incremental gas recovery and use over and above Option 1. As in Option 1, coal mines recover methane using vertical wells five years in advance of mining, horizontal boreholes one year in advance of mining, and gob wells, and sell gas to a pipeline. However, well spacing is tightened to increase recovery efficiency. Additionally, mines invest in enrichment technologies so that they are able to enrich and sell lower-quality gob gas to pipelines. This combination of tightened well spacing and gas enrichment increases recovery efficiency by 20 percent. Accordingly, this option assumes that an additional 20 percent of gas is available for sale to pipeline.

- Option 3: Catalytic Oxidation. Under this option, coal mines eliminate the methane in their ventilation air using a catalytic oxidizer system. This option can be implemented alone or in conjunction with either of the other two options. As described above, the heat produced is assumed to be used to produce electricity. At low energy prices for which the marginal cost of producing electricity from the heat exceeds the value of the electricity, the catalytic oxidizer is evaluated solely as a method for reducing emissions.

Options Not Included in the Analysis. This analysis incorporates all the major methods of recovering coal mine methane. Options 1 and 2 represent a range of effort with which methane may be recovered and enriched for use. More aggressive efforts, for example even tighter well spacing, may result in increased methane recovery and use in some cases depending on site-specific conditions. However, at some point the number of wells drilled will be limited by the cost of the wells relative to the incremental amount of gas that can be recovered.

In contrast to this assessment, earlier analyses examined recovering methane using vertical wells 10 years in advance of mining (e.g., EPA, 1993). Because production volumes and methane concentrations decline over time from vertical wells, this analysis conservatively assumes that vertical wells are only operated profitably for five years. The optimal period for operating the wells may be longer or shorter depending on local geologic conditions, costs, and the value of the energy produced.

By focusing on injecting the recovered gas into a pipeline, Options 1 and 2 exclude several additional options for using the gas, including:

- Electricity Production. Under Options 1 and 2 the recovered gas can be used in reciprocating engines or turbines to run a generator to produce electricity. This electricity can be used for on-site needs, such as for running the ventilation system. One of the advantages of producing electricity on-site is that low-quality gob gas can be used. Additionally, a portion of the ventilation air can be used as combustion air, thereby increasing the quantity of electricity generated and reducing the amount of methane that is released to the atmosphere in ventilation air. Electricity production is included as part of Option 3.

- Flaring. Under Options 1 and 2 the recovered gas can be flared. Flaring may be most advantageous for low-quality gob gas which cannot be injected into a pipeline without enrichment. This technology has been used at landfills and oil and gas production sites, but has not been implemented at U.S. coal mines due to concerns that a mishap at a flare could cause a mine fire.

- Local Use. Some coal mines are located near industrial and commercial facilities that may be able to use the coal mine methane recovered under Options 1 and 2. Depending on the use, a high quality source of gas may not always be needed, and thus the smaller cost of recovering and using coal mine methane may render this option feasible for smaller, less gassy mines.
- Use of Thermal Heat On-Site. Under Options 1 and 2 the recovered methane could be used in boilers or other equipment to produce heat or steam for on-site use. This option can be preferred when there are significant on-site heating needs. However, in most cases the on-site needs are less than the energy produced under Options 1 and 2.

Each of these gas use options could play a role in the cost curves, individually or in combination. For example, a portion of the recovered gas could be used on-site for heat in a coal preparation plant, while the highest quality gas is injected into a pipeline for sale. Because the preferred combination of options depends on site-specific conditions, this analysis focuses on pipeline injection for Options 1 and 2 because: (1) it is typically more cost effective than the other gas use options; and (2) it is broadly applicable to nearly all mining situations. By omitting these other options, the analysis is conservative in that there may be more cost-effective combinations of gas use possible at some mines due to site-specific conditions.

Interactions with Other Trends or Events Affecting Emissions. Energy prices are a key factor in determining the potential for coal mines to reduce emissions profitably. At higher energy prices, coal mine methane projects become increasingly attractive economically, so that mines producing less methane can successfully implement projects and reduce emissions.

The pattern of future coal production also has an important impact on both baseline methane emissions and the potential to reduce emissions from this source. Based on the latest projections from the 1998 Annual Energy Outlook (DOE, 1998), underground coal production is expected to grow at a faster rate than surface production through 2020. As underground coal production increases as a portion of total U.S. coal production, the potential to reduce methane emissions profitably increases because there are currently no technologies for reducing emissions from surface mined coal. This shift in production toward underground mines is included in this cost analysis.

In addition to shifting toward underground mining, the gassiness of the underground mines themselves may increase as companies mine deeper coal seams with higher gas contents. This trend would also affect baseline emissions and potential emissions reductions, but is not included in the analysis at this time.

Finally, it is expected that the efficiency and cost-effectiveness of degasification technologies will continue to improve. Over the last twenty years, the coal and coalbed methane industries have made many advances in well drilling and gas production techniques that both enhance recovery efficiency and lower production costs. This analysis assumes that recovery efficiency improves by 10 percent by 2020, but holds costs constant in real terms.

6.3 Methodology

The opportunity to reduce emissions was estimated by evaluating the ability of private decision makers (coal mine owners and operators) to build and operate systems for either recovering and using or oxidizing coal mine methane at a profit. To develop the cost curve, a range of energy prices was evaluated along with a range of emission reduction values. To determine profitability, the analysis estimates that in addition to the value of the energy produced, the mine owner/operator receives income equal to the emission reduction value times the amount of methane recovered. Profitability is estimated by comparing the value of the energy and the emission reduction to the costs of the system. The steps in the analysis are as follows:

Step 1: Define the Current Underground Mines. The analysis is performed on the underground mines that each released at least 0.5 MMcfd (million cubic feet per day) of methane from its ventilation system in 1996 (EPA, 1997b). These 70 mines account for about 95 percent of the methane released from underground mining in the U.S. Each of these mines is characterized in terms of: coal basin; annual coal production; methane released from the ventilation system; existence of degasification system; methane recovered by the degasification system (if one is present); and mining method (long wall or room and pillar) (EPA, 1997b and Keystone, 1997). In applicable cases the amount of methane recovered from existing degasification systems was estimated. Using these data, the rate of methane liberated per ton of coal mined is calculated for each mine. This liberation rate is used in the analysis to estimate the amount of gas available for recovery per ton of coal mined.

Step 2: Future Coal Production and Future Mines. The expected amount of future coal production from underground mines in the U.S. is taken from DOE (1998), and shows a 24 percent increase by 2010 and a 35 percent increase by 2020 relative to 1996 levels (see Exhibit 18). For purposes of this analysis, the characteristics of future mines are assumed to be the same as the characteristics of existing mines. Therefore, the data set of current mines is used to represent future mines, with the exception that coal production at each mine is scaled over time to the projected changes in U.S. coal production.

Step 3: Define "Model" Projects. To represent the three recovery and use options discussed above and defined in Exhibit 17, three model project configurations were defined in terms of the types and sizes of equipment required and the level of gas recovery achieved. The equipment requirements and their costs are listed in Exhibit 25. As shown in the exhibit, the number of wells required is a function of the amount of coal mined. The size and cost of other equipment is driven by the amount of gas produced, which depends on the amount of coal mined, the rate of methane liberated per ton of coal produced, and the recovery efficiency. For those mines that already have degasification systems in place, these costs were not included and were considered sunk costs. Costs for royalty payments are not included. The costs for the catalytic oxidizer system include the oxidizer itself and the cost of electric power generation equipment where applicable. When the oxidizer is used solely for oxidation with no electricity production, power generation costs are not included.

Exhibit 19 presents a summary of the estimated costs for each of the three options for a range of annual coal production values (1.0 to 5.0 million tons) and methane liberation values (200 to 3,500 cubic feet per ton). As shown in the exhibit, annual well drilling costs are driven by coal production. These annual costs include vertical wells and horizontal boreholes in advance of mining, and gob wells post-mining. Option 2 costs are incremental to the Option 1 costs, and include the costs of the gas enrichment system. The Option 3 costs include the costs of the oxidizer system, including the costs to run the fans for the oxidizer. For mines with methane liberation rates of 3,500 cubic feet per ton of coal mined, it is assumed in Exhibit 19 that the mine already has a degasification system, including vertical wells, horizontal boreholes, and gob wells. Consequently, the drilling costs for Option 1 are listed as zero. Additionally, the ventilation air handled by the oxidizer system is assumed to reflect the existence of a degasification system with a 50 percent recovery rate.

The extent of methane recovery and use for Option 1 varies by basin and is shown in Exhibit 20. As shown in the exhibit, the extent of methane recovery is assumed to increase over time as technology improves. Option 2 is estimated to have an incremental recovery efficiency of 20 percent over and above the amounts shown in Exhibit 20. The timing of the methane recovery is shown in Exhibit 21 for each of the well types. Vertical wells start producing gas five years prior to mining, while in-mine boreholes produce gas one year prior to mining. Gob wells produce gas in the year the coal is mined. The ventilation system emissions also occur in the year the coal is mined.

The catalytic oxidizer used in Option 3 is estimated to oxidize 98 percent of the methane that passes through the system.

Step 4: Calculate Break-Even Gas Prices for Options 1 and 2. A discounted cash flow analysis was performed to calculate the break-even gas price for Options 1 and 2 for each of the 70 mines for each of the years 2000, 2010, and 2020. The project costs were estimated for each mine using the assumptions and data defined in Step 3. The revenue associated with the project is estimated as the gas price times the amount of gas recovered and sold. The gas price needed to produce a net present value of zero is the breakeven gas price. The discounted cash flow parameters are as follows: real discount rate of 15 percent; marginal tax rate of 40 percent; 4 percent inflation; straight line depreciation; and project life of 15 years. The result of this step is a break-even gas price for each mine over time for each of the two options.

Step 5: Calculate a Break-Even Emission Reduction Value for Option 3. A discounted cash flow analysis was performed to calculate the emission reduction value that would be required to cover the costs of installing and operating the catalytic oxidizer system in Option 3. The analysis was performed for a 211,860 scf/min system with costs as described in Exhibit 25. Mines with larger air flow rates are assumed to use multiple units. The emission reduction value needed to offset the system costs to produce a net present value of zero was estimated to be the break-even emission reduction value. The value of the electricity produced is also included as revenue that offsets the cost of the system. As discussed above in Section 4, a base electricity price of $0.03/kWh was used to be representative of the value of displaced electricity purchases by the mine, or the price at which the mine could sell its electricity to the grid. The discounted cash flow parameters were: real discount rate of 15 percent; marginal tax rate of 40 percent; straight line depreciation; a depreciation period of 5 years; and a project life of 10 years.

Step 6: Estimate Emissions Reductions: Using the results from above, the profitable national emissions reductions for each year were estimated for a range of gas prices and emission reduction values. The base gas price is $2.525/MMBtu, which is the average wellhead gas price in key coal mine states (DOE, 1997).[4] Higher and lower prices were examined, ranging from 50 percent to 300 percent of the base gas price. The emission reduction value, expressed in $/ton of carbon equivalent, ranges from $0 to $200/ton. The emission reduction value was translated into a gas price using a global warming potential (GWP) of 21 and a methane energy content of 1,000 Btu/cubic foot. For Options 1 and 2, the emissions reductions are estimated to be the sum of the emissions that can be recovered profitably at the 70 mines for each combination of gas price and emission reduction value: if the break-even gas price for the mine is less than the sum of the estimated gas price plus the emission reduction value, the emissions can be reduced profitably. For Option 3, the break-even emission reduction value is used to define the cases in which this option is profitable. When profitable, the emission reduction is applied to all underground mining ventilation emissions.

The overall cost curve in terms of percent emissions reductions is estimated as the profitable emissions reductions divided by the total baseline emissions from all coal mining activities. Exhibit 22 lists the baseline estimates of methane liberated from coal mining and shows the portion of total liberations accounted for by underground mining activities. As shown in Exhibit 23, the emission reduction ranges from 18 to 73 percent for the energy prices and emission reduction values analyzed. Also shown in the exhibit are the equivalent gas prices that reflect the translation of the emission reduction value to an energy value. Exhibit 24 shows the cost curve results graphically by equivalent gas price. As shown in the exhibit, at slightly more than double the current energy price the catalytic oxidizer technology becomes profitable and significant emissions reductions are achieved. The total emission reduction is limited to about 75 percent because the remaining emissions are from surface mining and post-mining.

6.4 Limitations

The cost curve is based on the assumption that either the recovered methane is sold to a pipeline or that the methane in ventilation air is oxidized. But, there are a number of other uses to which recovered coal mine methane can be put, including power generation or local use, that may be more profitable. In terms of local use, this option may be especially feasible at smaller mines that have neighboring industrial/commercial facilities. Thus, the analysis may under-estimate the amount of feasible reductions that could be achieved since the break-even prices for a local project would likely be less than those for a pipeline injection project.

The 70 mines that were modeled in this cost curve analysis are the top mines in terms of their emissions. There are a number of mines with lower emissions for which methane recovery using degasification technologies were not examined because these mines are less likely to engage in profitable pipeline injection projects. In cases where these smaller mines could find profitable uses for the recovered methane (e.g., locally), the analysis under-estimates the feasible reductions that could be achieved.

[4] Wellhead gas price data are available for Alabama, Indiana, Kentucky and Ohio. Although data are not available for other coal mining states (West Virginia; Virginia; Pennsylvania; and Illinois), the wellhead prices in these states are expected to be similar to the average value used in the analysis because prices are heavily influenced by location along the gas transmission system.

Note, however, that the mines with lower emissions probably account for at most 10% of emissions from ventilation systems, so the under-estimate cannot be larger than this value.

Finally, this analysis does not account for any of the incremental benefits that may be achieved from implementing a methane recovery and use project at a mine, such as increased productivity or decreased ventilation costs. Thus, the analysis may under-estimate the quantity of methane emissions that could be achieved as a result of Options 1 and 2.

6.5 References

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Exhibit 16: Summary of Coal Mine Degasification System Options

Method	Description	Gas Quality/Btu Content (Btu/cf)	Drainage Efficiency*	Current Use in U.S. Coal Mines
Vertical Wells	Drilled from surface to coal seam years in advance of mining.	Produces nearly pure methane/ >950 Btu/cf	Up to 70%	Used by at least 3 U.S. mining companies in about 11 mines.
Gob Wells	Drilled from surface to a few feet above coal seam just prior to mining.	Produces methane that is sometimes contaminated with air/300-950 Btu/cf. Higher BTU gas is extracted during initial stage of gob well life.	Up to 50%	Used by approximately 22 mines.
Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane/ >950 Btu/cf.	Up to 20%.	Used by approximately 16 mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam several months or years prior to mining.	Produces nearly pure methane/ >950 Btu/cf.	Up to 50%.	Used by over 10 mines.
Cross-Measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata shortly prior to mining.	Produces methane that is sometimes contaminated with mine air/300-950 Btu/cf.	Up to 20%.	Not widely used in the U.S.

* Percent of total methane liberated that is recovered.

Source: EPA (1997b)

Exhibit 17: Summary of Options Included in the Coal Mine Cost Curve Analysis

Option	Technologies	Assumptions
1	Vertical Wells drilled five years in advance of mining; In-mine boreholes drilled one year in advance of mining; and gob wells.	All gas recovered from vertical wells and in-mine boreholes is sold to a pipeline. Only high quality gob gas is sold to the pipeline.
2	Vertical Wells drilled five years in advance of mining; In-mine boreholes drilled one year in advance of mining; and gob wells.	Incremental to Option 1 with tightened well spacing and gas enrichment. Recovery and use efficiency increases 20% over Option 1.
3	Catalytic Oxidation	Ventilation air is oxidized. No heat recovery value is obtained at low energy values. At higher energy values, however, the recovered thermal energy is assumed to be used for power generation.

Exhibit 18: Coal Production Forecasts

Year	Underground (UG) Production (million short tons)	% Increase in UG production (relative to 1996)	Total Coal Production (million short tons)	% Increase in Total Coal Production (relative to 1996)
1996	409.8	0%	1063.9	0%
2000	427.2	4.2%	1144.8	7.6%
2005	481.9	17.6%	1207.0	13.4%
2010	509.7	24.4%	1265.2	18.9%
2015	537.1	31.1%	1326.0	24.6%
2020	552.3	34.8%	1376.3	29.4%
Source: DOE (1998).				

Exhibit 19: Example Costs for Coal Mine Options

Coal Production (MM Ton/year)	Methane Liberated/ton (ft^3/ton)	Option 1			Option 2*			Option 3	
		Capital ($000)	Well Drill ($000)	O&M ($000)	Capital ($000)	Well Drill ($000)	O&M ($000)	Capital ($000)	O&M ($000)
1.0	200	$930	$570	$270	$2,400	$255	$260	$4,000	$200
3.0	200	$1,800	$1,700	$700	$2,850	$765	$430	$11,000	$600
5.0	200	$2,600	$2,850	$1,100	$3,300	$1,300	$775	$19,000	$1,000
1.0	1,000	$1,300	$570	$410	$2,800	$255	$320	$19,000	$1,000
3.0	1,000	$3,000	$1,700	$1,200	$4,100	$765	$600	$56,000	$2,900
5.0	1,000	$4,700	$2,850	$1,900	$5,400	$1,300	$875	$93,000	$4,900
1.0	3,500	$2,600	$0**	$890	$4,100	$255	$490	$33,000**	$1,700**
3.0	3,500	$6,900	$0**	$2,600	$8,000	$765	$1,100	$98,000**	$5,100**
5.0	3,500	$11,200	$0**	$4,300	$11,900	$1,300	$1,700	$164,000**	$8,600**

* Option 2 costs are incremental to Option 1.
** Assumes pre-existing vertical wells, gob wells, and horizontal boreholes required for mine operations.
Well Drill costs are annual drilling costs for all wells. All estimates are 1996 dollars.

Exhibit 20: Coal Basin Recovery Efficiencies by Year

Basin	1996	2000	2005	2010	2015	2020
Warrior	45.0%	45.0%	47.5%	50.0%	52.5%	55.0%
Illinois	50.0%	50.0%	52.5%	55.0%	57.5%	60.0%
Northern Appalachian	55.0%	55.0%	57.5%	60.0%	62.5%	65.0%
Central Appalachian	55.0%	55.0%	57.5%	60.0%	62.5%	65.0%
Western	50.0%	50.0%	52.5%	55.0%	57.5%	60.0%
Estimates developed based on experience with existing coal mine methane projects and data in EPA (1997b).						

Exhibit 21: Timing of Methane Production From Coal Mine Degasification Options

Year	Ventilation	Gob Wells	Horizontal Boreholes	Vertical Wells 5 Years in Advance of Mining
Mine-Through –5	0%	0%	0%	30%
Mine-Through –4	0%	0%	0%	25%
Mine-Through –3	0%	0%	0%	20%
Mine-Through –2	0%	0%	0%	15%
Mine-Through –1	0%	0%	100%	10%
Mine-Through Year	100%	100%	0%	0%
Total % for All Years	100%	100%	100%	100%
Estimates developed based on experience with existing coal mine methane projects and estimates in EPA (1993).				

Exhibit 22: Coal Mine Methane Liberation Estimates by Year

Year	Total Methane Liberated (MMcf)	Methane Liberated During UG Mining (MMcf)	UG Mining as a % of Total
1996	207,986	150,785	72.5%
2000	218,266	157,187	72.0%
2005	242,801	177,314	73.0%
2010	256,346	187,543	73.2%
2015	269,835	197,625	73.2%
2020	277,947	203,181	73.1%
Source: EPA (forthcoming).			

Exhibit 23: Emission Reduction For Coal Mines by Year (%)

(Emission Reduction Applies to Baseline of Methane Liberated shown in Exhibit 22)

2000	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	18%	28%	31%	71%	71%	71%	71%	71%	71%	71%	71%	71%
75% of Base	22%	31%	32%	71%	71%	71%	71%	71%	71%	71%	71%	71%
100% of Base	**30%**	**32%**	**34%**	**71%**	**71%**	**71%**	**71%**	**71%**	**71%**	**71%**	**71%**	**71%**
125% of Base	31%	33%	35%	71%	71%	71%	71%	71%	71%	71%	71%	71%
150% of Base	32%	34%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%
200% of Base	35%	35%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%
300% of Base	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%	71%

2010	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	21%	37%	39%	73%	73%	73%	73%	73%	73%	73%	73%	73%
75% of Base	32%	37%	42%	73%	73%	73%	73%	73%	73%	73%	73%	73%
100% of Base	**37%**	**40%**	**45%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**
125% of Base	38%	43%	45%	73%	73%	73%	73%	73%	73%	73%	73%	73%
150% of Base	41%	45%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%
200% of Base	45%	46%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%
300% of Base	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%

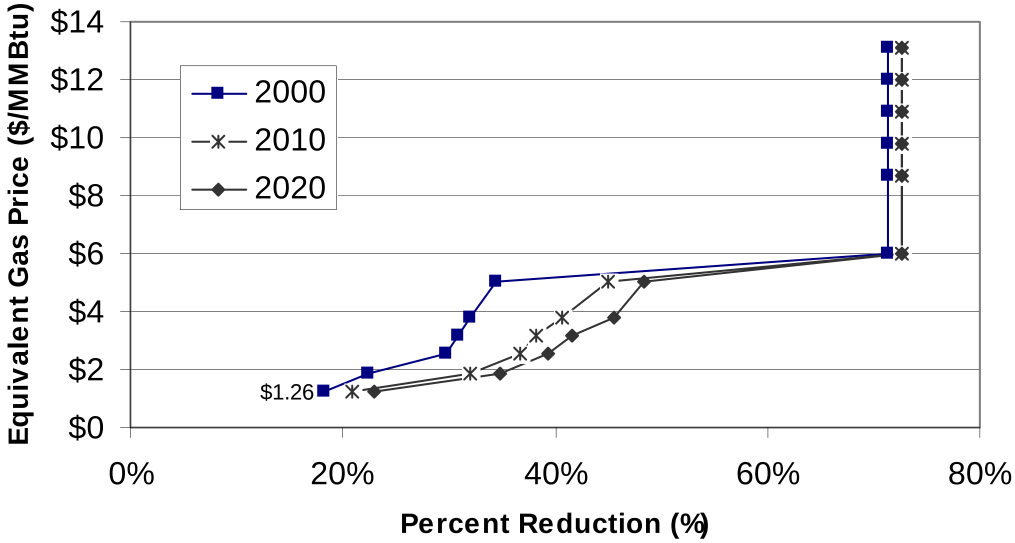
2020	Emission Reduction Value ($/ton of Carbon Equivalent)											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	23%	39%	43%	73%	73%	73%	73%	73%	73%	73%	73%	73%
75% of Base	35%	41%	46%	73%	73%	73%	73%	73%	73%	73%	73%	73%
100% of Base	**39%**	**45%**	**48%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**	**73%**
125% of Base	42%	47%	49%	73%	73%	73%	73%	73%	73%	73%	73%	73%
150% of Base	46%	48%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%
200% of Base	48%	49%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%
300% of Base	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%

Equivalent	Emission Reduction Value ($/ton of Carbon Equivalent)											
Gas Price ($/MMBtu)	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	$1.263	$2.362	$3.462	$4.561	$5.661	$6.761	$9.510	$12.259	$15.008	$17.757	$20.506	$23.255
75% of Base	$1.894	$2.993	$4.093	$5.193	$6.292	$7.392	$10.141	$12.890	$15.639	$18.388	$21.137	$23.886
100% of Base	**$2.525**	**$3.625**	**$4.724**	**$5.824**	**$6.924**	**$8.023**	**$10.772**	**$13.521**	**$16.270**	**$19.020**	**$21.769**	**$24.518**
125% of Base	$3.156	$4.256	$5.356	$6.455	$7.555	$8.654	$11.404	$14.153	$16.902	$19.651	$22.400	$25.149
150% of Base	$3.788	$4.887	$5.987	$7.086	$8.186	$9.286	$12.035	$14.784	$17.533	$20.282	$23.031	$25.780
200% of Base	$5.050	$6.150	$7.249	$8.349	$9.449	$10.548	$13.297	$16.046	$18.795	$21.545	$24.294	$27.043
300% of Base	$7.575	$8.675	$9.774	$10.874	$11.974	$13.073	$15.822	$18.571	$21.320	$24.070	$26.819	$29.568

Baseline Methane Liberated: 2000 = 4.2 Tg; 2010 = 4.9 Tg; 2020 = 5.3 Tg.

Exhibit 24: Emission Reduction Versus Equivalent Gas Price For Coal Mines by Year (%)

Baseline Methane Liberated: 2000 = 4.2 Tg; 2010 = 4.9 Tg; 2020 = 5.3 Tg.



This cost curve has two distinct parts. At equivalent energy prices below about $6/MMBtu, the emissions reductions are achieved through the use of the degasification technologies. The methane is recovered and injected into the natural gas system. In this portion of the graph, the emission reduction increases with increasing prices because additional mines find it profitable to undertake these projects. At an equivalent gas price of approximately $5.50, the catalytic oxidizer technology becomes profitable. Consequently, all methane emissions from ventilation air can be addressed profitably, and the curve becomes vertical. At these prices, all methane emissions from underground mining are reduced by 98 percent, the effectiveness of the oxidizer.

Exhibit 25: Summary of Data and Assumptions Used in the Coal Mine Analysis

Cost Item	Number or Size of Units Needed	Cost Per Unit	Notes
Costs for Wells			
Vertical Well	Option 1: 1 well for every 250,000 tons of coal mined Option 2: 1 well for every 1 million tons of coal mined.	$150,000/well	Option 2 is incremental to Option 1.
Gob Wells	Option 1: 1 well for every 500,000 tons of coal mined Option 2: 1 well for every 1 million tons of coal mined	$30,000/well	Option 2 is incremental to Option 1.
In-Mine Boreholes	Option 1: 1 well for every 500,000 tons of coal mined Option 2: 1 well for every 1 million tons of coal mined	$75,000/well	Option 2 is incremental to Option 1.
Well Water Disposal Costs (vertical wells only)	1 barrel of water is produced per mcf (thousand cubic feet) of gas produced.	$0.50 per barrel per year.	
Compression Costs			
Wellhead compressor	1 per well at 200 HP/mmcfd	Capital costs: $600/HP; O&M costs: $20/HP.	
Satellite compressor	1 per project at 150 HP/mmcfd		
Sales compressor	1 per project at 150 HP/mmcfd		
Gathering Line and Pipeline Costs			
Gathering Lines from Wellhead to Satellite	Length of Gathering Lines from Each Well to Satellite = 2000 ft.	$10/ft	
Gathering Lines from Satellite to Point of End-Use	Length of Gathering Lines from Satellite to Point of End-Use = 26,400 ft (5 miles)	$15/ft	
Cost of Moving Gathering Lines		$5/ft per year	
Gas Processing Costs			
Dehydrator	1 per project	Capital Cost: $40,000; O&M cost: $3,000.	

Cost Item	Number or Size of Units Needed	Cost Per Unit	Notes
Gas Enrichment (Fixed Capital Cost) $/project	Required for Option 2 only.	$1,888,500	
Gas Enrichment (Variable Capital Cost) $/MMCFD	Required for Option 2 only.	$526,000	
Gas Enrichment (Fixed Annual Operating Cost) $/yr	Required for Option 2 only.	$132,000	
Gas Enrichment (Operating cost based on max gas production) $/MMCFD	Required for Option 2 only.	$37,167	
Oxidizer Costs			
Oxidizer (with electricity generation)	Option 3 only.	Capital Cost: $10.4 million; O&M Costs: $541,740	Costs are for a system capable of handling 211,860 scf/min of ventilation air at 0.5% methane.
Oxidizer (without electricity generation)	Option 3 only.	Capital Cost: $6.2 million; O&M costs: $541,740	Costs are for a system capable of handling 211,860 scf/min of ventilation air at 0.5% methane.
Discounted Cash Flow Assumptions			
Methane production from degasification	Methane recovery rates vary by basin and improve over time. See Exhibit 20.		
Cash Flow Parameters	Real discount rate of 15 percent. Marginal tax rate of 40 percent Project life: degasification=15 years ; oxidizer=10 years Straight line depreciation		
Energy Prices	Base gas price of $2.525/MMBtu developed from wellhead gas prices. See footnote 4 on page 33.		
Sources: EPA (1997a, 1997b, 1997c), Trottier (1998).			

7. U.S. COST ANALYSIS: METHANE EMISSIONS FROM NATURAL GAS AND OIL SYSTEMS

Cost curves for reducing methane emissions from natural gas systems are based on technologies and practices for reducing leaks and preventing deliberate and incidental venting of methane. Emissions reductions are estimated to be the amount of methane emissions that can be prevented profitably at each of the energy prices and emission reduction values examined. This analysis is based on data from the Natural Gas STAR Program, a joint EPA-natural gas industry program that is identifying and promoting profitable options for reducing emissions. Options for reducing methane emissions from oil systems are being researched. Thus, cost curves are not yet available for oil systems.

7.1 Source Summary

Methane is the principal component (95 percent) of natural gas. The U.S. consumes over 20 trillion cubic feet (Tcf) of natural gas annually, and leaks or deliberate releases during natural gas production, processing, transmission and distribution emit methane directly into the atmosphere. Because natural gas is often found in conjunction with oil, oil production and processing also emit methane. For 1997, the preliminary estimate of methane emissions is approximately 6.1 Tg from natural gas systems and 1.2 Tg from oil systems (EPA, forthcoming). Exhibit 26 summarizes the distribution of emissions across gas industry sectors: production, processing, storage, transmission, and distribution (exhibits are presented at the end of the section, starting on page 47). In the oil industry, methane emissions are concentrated in the production and crude oil storage sectors. The sources of methane leaks are well understood, although the amount of leakage is still subject to considerable uncertainty mainly due to the continental scope of natural gas and oil systems. There are hundreds of thousands of oil and gas wells, thousands of crude oil storage tanks, and over one million miles of gathering, transmission, distribution and service pipe, and supporting facilities and equipment.

7.2 Scope of Emissions Reductions

The analysis of potential methane emissions reductions is based on specific technologies and practices identified in the Natural Gas STAR Program, including best management practices (BMPs) that can reduce emissions profitably at today's gas prices. The natural gas and oil industries have an economic incentive to reduce methane emissions because methane emissions are a loss of product. Methane leaks are also repaired for safety reasons, to prevent explosions. In other cases methane emissions reductions are a by-product of other environmental activities, such as reducing hazardous air pollutant emissions.

Options Included in the Analysis*:* BMPs identified and analyzed to date in the Natural Gas STAR program include the following. Exhibit 27 describes these options in greater detail.

- Replacing or repairing high bleed pneumatic devices with low bleed devices
- Directed inspection and maintenance of compressor stations
- Reducing recirculation rates on glycol dehydrators
- Installing flash tanks on glycol dehydrators
- Installing fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line
- Installing static seal systems on reciprocating compressor rods
- Installing dry seal systems on centrifugal compressors
- Directed inspection and maintenance of gate stations and surface facilities

These options were developed by EPA in cooperation with the natural gas industry through the Natural Gas STAR Program and documented in a series of Lessons Learned Studies published by the EPA (EPA, 1997a-h).

In addition, Partners in the Natural Gas STAR Program have identified over 50 additional opportunities to reduce methane emissions (EPA, 1997i). This cost analysis incorporates some of the more promising and applicable of these additional practices, listed below. This list is considered tentative and must be studied further. Exhibit 28 describes these options in greater detail.

- Directed inspection and maintenance of production sites, processing sites, transmission pipelines, storage wells, and liquid natural gas stations
- Enhanced directed inspection and maintenance at production sites, surface facilities, storage wells, offshore platforms, and compressor stations
- Installation of electric starters on compressors
- Installation of plunger lifts at production wells
- Use of capture vessels for blowdowns at processing plants and other facilities
- Installation of instrument air systems
- Use of portable evacuation compressors for pipeline repairs
- Installation of catalytic converters on compressor engines
- Electronic metering
- Replacing cast iron distribution mains with steel or plastic pipe
- Replacing cast iron distribution services pipe with steel or plastic pipe

Options Not Included in the Analysis: The above lists of options to reduce methane emissions are not exhaustive. Many Partner-reported opportunities have not yet been fully characterized, so further research is necessary. In addition, at high values per ton of methane emissions avoided it should be expected that industry innovation will lead to activities and technologies that do not exist today.

Interactions with Other Trends or Events Affecting Emissions: Improvements in technology, efforts to comply with non-methane emission regulations and safety concerns affect methane emissions. The natural gas industry, like most industries, has experienced ongoing broad-based technology improvements. These improvements in technology have increased operating efficiency and have created a trend of reduced methane emission rates. In the natural gas industry, technology improvements are estimated to reduce methane emission rates by 5 percent by 2020. This independent trend is included in the baseline emissions estimates[5] and consequently is not added to the emission reduction estimates in this cost analysis.

In some cases, methane emissions are reduced as a side-effect of efforts to comply with regulations for hazardous air pollutants (HAPs). For example, instrument air systems and vapor recovery units reduce methane emissions and are often installed to meet emission standards for benzene, toluene, ethylbenzene and xylene (collectively these four HAPs are referred to as BTEX). In addition, maintenance completed for safety concerns often reduces methane emissions. One example is the replacement of leaky distribution pipeline.

7.3 Methodology

The opportunity to reduce emissions was estimated by evaluating the ability of private decision makers (gas and oil system operators) to implement technologies and practices that reduce emissions at a profit. To develop the cost curve, a range of gas prices was evaluated along with a range of emissions reduction values. To determine profitability, the analysis estimates that in addition to the value of the gas saved by avoiding emissions, the system operator realizes income equal to the emissions reduction value times the amount of methane emissions avoided. Profitability is estimated by comparing the value of the gas and the emissions reduction to the costs of the technology or practice. The total reductions achievable under

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[5] The 5 percent reduction is included in the baseline emission estimates by reducing the emission factors over time at a rate that yields a 5 percent reduction between 1995 and 2020.

each gas price and price per ton of carbon equivalent is the sum of the reductions across all of the options. The analysis consists of the following steps.

Step 1: Define Technologies and Practices: Each of the technologies and practices for reducing methane emissions is defined in terms of the following: emissions source to which it applies; capital cost; number of years that the capital equipment lasts (typically 5 to 15 years depending on the technology); annual operating and maintenance costs; portion of the emissions source to which the technology or practice applies (up to 100 percent); and emissions reduction achieved (up to 100 percent). In particular, the technologies and practices are defined to match the emissions source definitions in the emissions inventory analysis (EPA, 1996). Additionally, in some cases the technologies and practices build on each other and must be considered in proper order. These relationships are defined so that incremental emissions reductions are analyzed for each option. Exhibit 29 and Exhibit 30 list the data used to define the BMPs analyzed in the Lessons Learned Studies and the additional opportunities, respectively.

Step 2: Break-Even Gas Prices: A discounted cash flow analysis was performed for each technology and practice to estimate the gas price at which the costs of the technology or practice is exactly offset by the value of the gas saved by preventing the emissions. The analysis uses a 15 percent real discount rate, a 40 percent marginal tax rate, and straight-line depreciation of capital equipment. For those technologies that destroy the emissions as opposed to saving the gas (e.g., catalytic converters on engine exhaust), the break-even price is the value of the emissions reduction that would be needed to motivate the installation of the technology.

Step 3: Profitable Emissions Reductions: Using the break-even gas prices, the technologies and practices are identified that would be profitable at a range of gas prices and emissions reduction values. The base gas prices are the national average 1996 prices at the segments of the industry: wellhead - \$2.17/MMBtu; pipeline - \$2.27/MMBtu; and citygate - \$3.27/MMBtu (DOE, 1997). Emissions reduction values in \$/ton of carbon equivalent are converted to \$/MMBtu of gas using a global warming potential (GWP) of 21 and an energy value of gas of 1,000 Btu per cubic foot. Exhibit 31 summarizes the data and assumptions used in the profitability analysis.

Step 4: Cost Curve: The cost curve is estimated by summing across all the profitable emission reduction options at each combination of gas price and emission reduction value. The total emissions reductions are divided by the baseline emissions to estimate emissions reductions in percent, as shown in Exhibit 32. Also shown in the exhibit are the incremental gas prices estimated for each of the emission reduction values. These incremental values are added to the base gas prices for each segment of the natural gas system. These emission reduction estimates, based on the 1992 emissions inventory, can be applied to future years insofar as the mix of emissions sources remains relatively constant, as anticipated.

Exhibit 33 shows the emission reduction graphically by equivalent gas price, and shows reductions by industry segment. As shown in the exhibit, the maximum total emissions reductions are on the order of 50 percent. The maximum emission reduction achievable varies by segment, with the transmission sector having the largest potential at all gas prices. These large reductions in the transmission segment are achieved through the implementation of: directed inspection and maintenance at compressor stations; technologies for reducing emissions from compressor seals; replacement of high bleed pneumatic devices; and installation of catalytic converters on compressor engines.

7.4 Limitations

This analysis is limited in several respects. First, it does not include the cost of reducing emissions from oil systems. Analysis is ongoing to improve the basis for estimating methane emissions from oil systems. Once this is completed, the next step will be to evaluate emission reduction opportunities.

A second limiting factor is the lack of data about other potential technologies or practices for reducing methane emissions from natural gas facilities. Unlike those practices studied as part of the Natural Gas STAR Lessons Learned program, no detailed economic or technical analyses have been undertaken of these additional practices and thus the characterizations and costs used in this analysis is considered preliminary. Lessons Learned Studies for these other practices are under development.

In addition, the list of technologies and practices to reduce methane emissions is not complete. There may be other emission-reducing practices that have not been identified by the natural gas industry because it is believed that the costs of reduction are too high given current gas prices. Therefore, the cost curve may not represent all of the opportunities to lower methane emissions at higher price levels.

Finally, a major source of uncertainty about the emissions reductions is how specific reduction technologies and practices are applied to the underlying emissions inventory and forecast. In many cases, estimating reductions requires applying specific practices to general categories of emissions, as for example, where the reductions achieved by installing static packs on reciprocating compressors requires estimating the amount of time reciprocating compressors are off-line. The multiple estimates involved in generating a single emission reduction estimate leads to multiple uncertainties.

7.5 References

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Exhibit 26: Sources of Methane Emissions from U.S. Oil and Gas Activities (1996)

Industry Sector	Natural Gas Industry		Crude Oil Industry	
	Sources of Emissions	% of Total	Sources of Emissions	% of Total
Production	Wellheads, dehydrators, separators, gathering lines, pneumatic devices	23	Wellheads, separators, venting and flaring, other treatment equipment	49
Processing	Compressors and compressor seals, piping, pneumatic devices, and processing equipment	10	Waste gas streams during refining	2
Storage	Injection/withdrawal wells, pneumatic devices, and dehydrators	1	Crude oil storage tanks	48
Transmission	Compressor stations (blowdown vents, compressor packing, seals, valves), pneumatic devices, pipeline maintenance, and accidents	39	Transportation tanker operations	< 1
Distribution	Gate stations, underground non-plastic piping (cast iron mainly), third party damage	27	Not Applicable	

Exhibit 27: Best Management Practices Analyzed in the Lessons Learned Studies Used to Develop Cost Curves for Reducing Methane Emissions from the U.S. Natural Gas Industry

Option	Description
Replacing or repairing high bleed pneumatics devices with low bleed devices	High bleed rate pneumatic devices that employ gas to operate the actuators are ubiquitous in the industry and are a major source of emissions. Replacing them with low bleed devices where possible reduces emissions considerably.
Directed inspection and maintenance of compressor stations	Compressor stations have a vast number of pipes, valves, and other equipment that leak. As with gate stations, very few leaks account for the total volume of emissions. The same strategy applied to compressor stations will reduce the vast majority of emissions at a low cost.
Reduce glycol recirculation rates on glycol dehydrators	Glycol dehydrators remove water from gas at the wellhead. The glycol also absorbs methane, which is vented to the atmosphere when the glycol is regenerated, at a rate directly proportional to the glycol circulation rate. Glycol is often over-circulated. Proper circulation rates can achieve pipeline water content requirements and reduce methane emissions.
Installing flash tanks on glycol dehydrators	Glycol dehydrators remove water from gas at the wellhead. The glycol also absorbs methane, which is vented to the atmosphere when the glycol is regenerated. Flash tanks capture 90 percent of the methane before it reaches the reboiler.
Installing fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line	When compressors are not running and are taken “offline,” they are often purged of the gas in the compression chambers and isolated from the high-pressure pipeline with much leakage occurring at the isolation valves. Keeping the isolated compressor pressurized and bleeding off the gas into a fuel gas system reduces losses to the atmosphere
Installing static-seal compressor rod packing on reciprocating compressors	Compressor rod packing keeps gas from the compressor from escaping along the shaft into the compressor housing. Packing leaks are greater while compressors are off-line and remain pressurized. Static-packs clamp down on the compressor rod when compressors are idle to reduce leakage.
Installing dry seal systems on centrifugal compressors	Centrifugal compressors have elaborate sealing systems to keep high-pressure gas in the compressor from escaping. Wet seal systems use high-pressure oil as the seal. The oil absorbs gas and which is vented when the sealing oil is circulated. Dry seal systems use high pressure air to establish a seal and avoid these losses.
Early replacement of rings and rods on centrifugal compressors	By using company-specific financial objectives and monitoring data, natural gas transmission companies can determine emission levels at which it is cost effective to replace rings and rods.
Directed inspection and maintenance of gate stations and surface facilities	Gate Stations are where high transmission pipeline pressures are dropped down to distribution system pressures; other surface facilities also regulate pipeline pressures. Emissions occur at the equipment, joints, and valves at these facilities. A few stations and equipment types account for most of the emissions. Directed inspection and maintenance uses leak rate data and economic criteria to focus repairs on the costliest leaks.

Exhibit 28: Additional Partner Reported Opportunities Used to Develop Cost Curves for Reducing Methane Emissions from the U.S. Natural Gas Industry

Option	Description
Directed inspection and maintenance of production sites, processing sites, transmission pipelines and liquid natural gas stations	Emissions occur at the equipment, joints, valves at these facilities. Directed inspection and maintenance uses leak rate data and economic criteria to focus repairs on the costliest leaks.
Enhanced directed inspection and maintenance at production sites, surface facilities, storage wells, off-shore platforms, and compressor stations	Enhanced DI&M is increased frequency of survey and repair.
Installation of electric starters on compressors	Compressor engines are often started using a blast of high-pressure natural gas. Electric starters can replace these gas starters and avoid methane emissions.
Installation of plunger lifts at production wells	A plunger lift is an artificial lift that assists gas production by producing liquids the natural gas reservoir can no longer continually produce. Plunger lifts prolong well life, increase productivity and reduce methane emissions.
Use of capture vessels for blowdowns at processing plants and other facilities	A capture vessel can be used during blowdowns to avoid venting methane to the atmosphere. The captured natural gas can be re-routed to pipelines or used on-site as fuel.
Installation of instrument air systems	Methane leaks from pneumatic devices can be avoided by installing instrument air systems which open and close valves using electricity instead of pressure from gas systems.
Use of portable evacuation compressors for pipeline repairs	A portable compressor can be used to evacuate the gas in an area of blocked-off pipeline that is about to be repaired. This gas can be re-routed to the pipeline.
Installation of catalytic converter on compressor engines	A catalytic converter is an afterburner that reduces pollution from incomplete fuel combustion. Methane is combusted, and the energy from combustion is unused, so benefits are restricted to the value placed on reducing methane emissions.
Electronic metering	Replacing old pneumatic-based meter runs at gate stations with electronic meters will reduce methane emissions.
Replacing cast iron distribution mains with protected steel or plastic pipe	Cast iron and unprotected steel pipeline is replaced with materials less prone to corrosion and leaks.
Replacing cast iron distribution services with protected steel or plastic pipe	Cast iron services are replaced with materials less prone to corrosion and leaks.

Exhibit 29: Cost Analysis Data and Assumptions for Natural Gas System Best Management Practices Analyzed in the Lessons Learned Studies

Best Management Practice	Applicability and Emissions Reductions	Costs	Break-Even Gas Price
Replacing High-Bleed Pneumatics with Low-Bleed Pneumatics	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission Reduction: 50%-90%. For all sectors, applicability and emissions reductions are higher for high-bleed devices. For the production sector, 6 cases were examined (low-med.-high bleed; intermittent & continuous). For the transmission sector, 9 cases were examined (low-med.-high bleed; continuous, turbine and displacement).	Capital: $750/device ($1,500 per device x 0.5 to reflect early replacement) Annual O&M: None	$0.46-$16.75 for the production sector. Break-even gas prices are lower for high-bleed devices. $0.19-$296 for the transmission sector. Break-even gas prices are lower for high-bleed devices.
Directed I&M at Compressor Stations	Applicability: 100% of compressor stations in the transmission sector Emission Reduction: 12%	Capital: $5,000/station instrument spread across 10 facilities yielding $500/facility. Annual O&M: $2,065/station	$0.54 for storage compressor stations $0.61 for trans. compressor stations
Reduce Glycol Recirculation Rates on Dehydrators	Applicability: 100% of dehydrators in production, processing and transmission sector Emission Reduction: 30-60% for production and processing, 30% for transmission For the production and processing sectors, 4 cases were examined (with/ & without flash tanks; with and without pumps).	Capital: $0 Annual O&M: $50/dehydrator	$0.45-$101 for dehydrators in production and processing sector $4.70 for dehydrators without flash tanks in transmission sector $19.86 for dehydrators with flash tanks in transmission sector
Install Flash Tank Separators on Glycol Dehydrators	Applicability: 100% of glycol dehydrators without flash tanks in the production, processing and transmission sector. Emission Reduction: For the production and processing sectors, 12%-63% for dehydrator vents and 63% for Kimray pumps. For the transmission sector, 90% for dehydrators with gas-assisted pumps, 30% for dehydrators without gas-assisted pumps.	Capital: $8,000/dehydrator Annual O&M: None	$8.84 for dehydrators with gas assisted pumps and $216 for dehydrators without gas assisted pumps on dehydrator vents in the production and processing sectors $8.84 for dehydrators on Kimray pumps in the processing sector $3.18 for transmission sector

Best Management Practice	Applicability and Emissions Reductions	Costs	Break-Even Gas Price
Fuel Gas Retrofit	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 36% for reciprocating compressors in the transmission sector, 21.3% for reciprocating. compressors in gas processing plants.	Capital: $1,250/compressor. Annual O&M: None	$0.11 for storage compressor stations $0.16 for trans. compressor stations $0.37 for processing compressor stations
Static-seal Compressor Rod Packing	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 6.0% for storage compressor stations, 8.7% for trans. compressor stations	Capital: $3,000/compressor Annual O&M: none	$1.69 for storage compressor stations $1.62 for trans. compressor stations
Change Wet Seals to Dry Seals on Centrifugal Compressors	Applicability: 100% of all centrifugal compressors in the processing and transmission sectors Emission Reduction: 77.2% for storage compressors, 70.9% for trans. compressor stations, 65.9% for processing compressors.	Capital: $240,000/compressor. Annual O&M: savings in material and labor relative to wet seals of $63,000/compressor.	$1.02 for storage compressor stations $1.12 for trans. compressor stations $1.72 for processing compressor stations
Early Replacement of Rings and Rods on Reciprocating Compressors	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 1.4% for storage compressor stations, 1.5% for trans. compressor stations	Capital: $100/compressor Annual O&M: None	$0.95 for storage compressor stations $1.21 for trans. compressor stations
Directed I&M at Gate Stations and Surface Facilities	Applicability: For transmission sector, 100% of trans. co. interconnect M&R stations. For distribution sector, 100% of high pressure, 50% of medium pressure, and 0% of low pressure stations. Emission Reduction: For transmission sector, 33%. For distribution sector, 33% for high pressure, 25% for medium pressure stations.	Capital: $5,000/survey instrument spread across 20 facilities yielding $250/station. Annual O&M: $295/station	$0.74 for transmission sector. For distribution sector: $0.69 for M&R >300 $1.72 for M&R 100-300 $95.31 for M&R <100

Exhibit 30: Cost Analysis Data and Assumptions for Additional Partner Reported Opportunities – Natural Gas Systems

Additional Partner Reported Opportunity	Applicability and Emissions Reductions	Costs	Break-Even Gas Price
Directed I&M at Production Sites	Applicability: 100% of non-associated gas wells, 100% of off-shore platforms, and 100% of pipeline leaks in the production sector. Emission Reduction: 33% for non-associated gas wells, 33% for off-shore platforms, and 60% for pipeline leaks.	Capital: $200/well, $6,000/off-shore platform, $100/mile of pipeline Annual O&M: $300/well, $2,000/off-shore platform, $150/mile of pipeline	$411 for eastern on-shore non-associated gas wells $80.26 for rest of U.S. gas wells $10.13 for Gulf of Mexico off-shore platforms $25.06 for rest of U.S. off-shore platforms $15.10 for pipeline leaks
Enhanced Directed I&M at Production Sites	Applicability: 100% of non-associated gas wells in the production sector Emission Reduction: 50%	Capital: $500 Annual O&M: $700	$639 for eastern on-shore non-associated gas wells $125 for rest of U.S. gas wells
Electric Starter	Applicability: 100% of compressor starts in the production sector Emission Reduction: 75%	Capital: $20,000/compressor Annual O&M: $5,000/compressor	$1,420
Plunger Lift Well	Applicability: 20% of Appalachia (all non-associated) and 20% of rest of U.S. on-shore wells in the production sector Emission Reduction: 20%	Capital: $2,500/well Annual O&M: $100/well	$1,155 for Appalachia wells $226 for rest of U.S. on-shore wells
Use Surge Vessel to Capture Blowdowns	Applicability: 100% of pipeline venting during routine maintenance and upsets in production, processing and transmission sector Emission Reduction: 50%	Capital: $100,000/vessel-compressor-station (unit depends on sector) Annual O&M: $2,000/unit	>$100,000 for vessel blowdowns in the production sector $11,644 for compressor blowdowns in the production sector $9.43 for processing $8.78 for transmission

Additional Partner Reported Opportunity	Applicability and Emissions Reductions	Costs	Break-Even Gas Price
Install Instrument Air Systems	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission Reduction: 100% For pneumatic device vents in the production sector, 6 cases were examined (low-med.-high bleed; intermittent & continuous). For the transmission sector, 9 cases were examined (low-med.-high bleed; continuous, turbine & displacement). Applicability is higher for high-bleed devices.	Capital: $4,200 Annual O&M: various ($750 for pneumatic device vents in the production sector, $196 for chemical injection pumps in the production sector)	$4.49-$49.08 for pneumatic device vents in the production sector. Break-even gas prices are lower for high-bleed devices. $14.20 for chemical injection pumps in the production sector $3.21-$821 for the transmission sector. Break-even gas prices are lower for high-bleed devices.
Use Portable Evacuation Compressors	Applicability: 90% of pipeline venting during routine maintenance and upsets in production and transmission sector Emission Reduction: 80%	Capital: $1,400/mile Annual O&M: $10/mile	$1,011 for production sector $9.87 for transmission sector
Directed I&M at Processing Sites	Applicability: 100% of processing plants Emission Reduction: 33%	Capital: $1,000/plant Annual O&M: $2,000/plant	$2.37
Catalytic Converters on Engine Exhaust	Applicability: 75% of engines and turbines in the transmission sector (including LNG storage) Emission Reduction: 75%	Capital: $3,386/MM HP-Hr ($20,000/engine) Annual O&M: $168/MM HP-Hr ($1,000/engine)	$4.67 for engines (transmission) $82.57 for turbines (transmission) $6.40 for engines (storage) $75.00 for turbines (storage) $9.21 for engines (LNG storage) $418 for turbines (LNG storage)
Directed I&M at LNG Stations	Applicability: 100% of LNG stations in transmission sector Emission Reduction: 60%	Capital: $500/station Annual O&M: $2,065/station	$1.86
Directed Inspection and Maintenance of Transmission Pipelines	Applicability: 100% of pipeline leaks in the transmission sector. Emission Reduction: 60%	Capital: $100 Annual O&M: $150	$521
Enhanced Directed I&M at Compressor Stations	Applicability: 100% of compressor stations in the transmission sector Emission Reduction: 26.5% for storage compressors, 18.9% for trans. compressor stations	Capital: $1,000/station Annual O&M: $6,000/station	$0.68 for storage compressor stations $1.10 for trans. compressor stations

Additional Partner Reported Opportunity	Applicability and Emissions Reductions	Costs	Break-Even Gas Price
Directed Inspection and Maintenance at Storage Wells	Applicability: 100% of storage wells in the transmission sector. Emission Reduction: 33%	Capital: $200/well Annual O&M: $200/well	$18.26
Enhanced Directed Inspection and Maintenance at Storage Wells	Applicability: 100% of storage wells in the transmission sector. Emission Reduction: 50%	Capital: $300/well Annual O&M: $400/well	$22.87
Enhanced Directed I&M at Gate Stations and Surface Facilities	Applicability: 100% of gate stations and surface facilities in the distribution sector Emission Reduction: 30%-80%, depending on station pressure. Higher pressure stations have greater percent emissions reductions.	Capital: $1,000/station Annual O&M: $1,000/station	$1.00 for M&R >300 $2.31 for M&R 100-300 $111 for M&R <100
Electronic Metering	Applicability: 100% of trans. co. interconnect M&R stations in the transmission sector. 100% of meter and regulator stations at city gates in distribution sector. Emission Reduction: 95%	Capital: $15,000/station Annual O&M: $2,500/station	$4.63 for the transmission sector For the distribution sector: $4.27 for M&R >300 $8.03 for M&R 100-300 $178 for M&R <100
Pipeline Replacement	Applicability: 100% of cast iron and unprotected steel mains in distribution sector Emission Reduction: 95%	Capital: $1,000,000/mile Annual O&M: $50/mile	$1,144 for cast iron pipeline $2,479 for unprotected steel pipeline
Services Replacement	Applicability: 100% of unprotected steel services in distribution sector Emission Reduction: 95%	Capital: $250,000/service Annual O&M: $50/service	$40,176 for unprotected steel services

Exhibit 31: Profitability Analysis Data and Assumptions

Element	Description
Discounted Cash Flow Parameters	Real discount rate of 15 percent Marginal tax rate of 40 percent Project lifetime set to the life of the equipment, typically 5 to 15 years Straight line depreciation
Base Gas Prices	Wellhead: $2.17/MMBtu Pipeline: $2.27/MMBtu Citygate: $3.27/MMBtu
Value of Emission Reduction	The value of emission reduction is estimated as the emissions avoided times the value ($/ton of carbon equivalent) taking into account the GWP of methane (21). The value of the gas itself is also included where applicable.

Exhibit 32: Emission Reduction For Gas Systems (%)

All Years	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	23%	29%	31%	32%	34%	36%	43%	47%	47%	49%	49%	49%
75% of Base	28%	31%	32%	33%	34%	36%	46%	47%	48%	49%	49%	49%
100% of Base	**29%**	**32%**	**32%**	**33%**	**34%**	**37%**	**46%**	**47%**	**48%**	**49%**	**49%**	**49%**
125% of Base	31%	32%	33%	33%	35%	37%	46%	47%	49%	49%	49%	49%
150% of Base	32%	32%	33%	34%	36%	39%	47%	47%	49%	49%	49%	49%
200% of Base	32%	33%	34%	34%	37%	44%	47%	48%	49%	49%	49%	49%
300% of Base	34%	34%	36%	42%	43%	45%	47%	49%	49%	49%	49%	49%

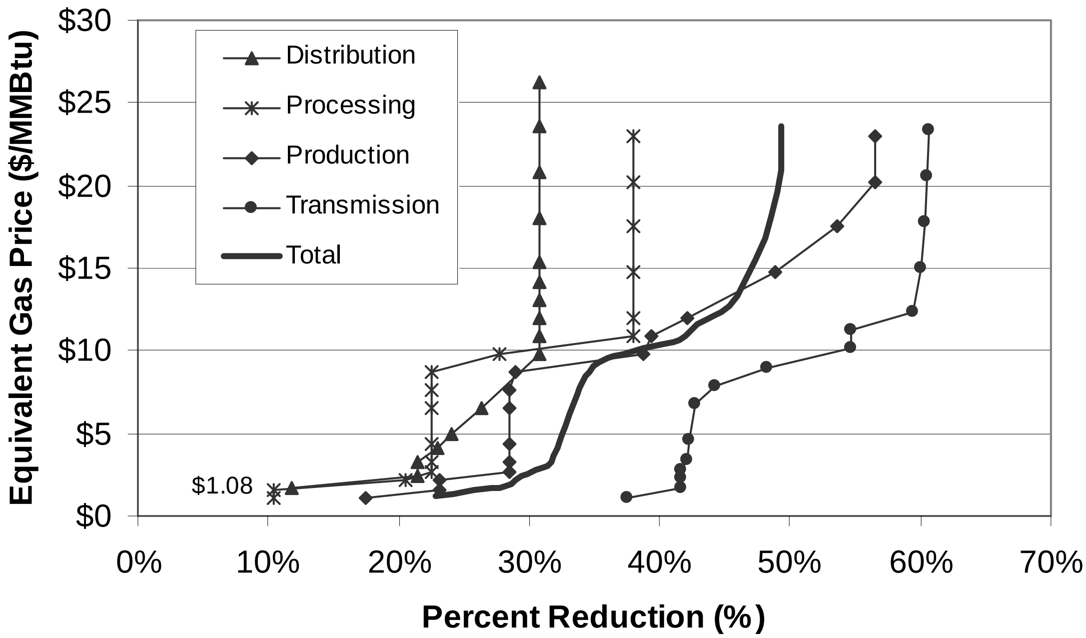
Reduction Value ($/MMBtu)	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
Incremental Gas Price	$0.000	$1.100	$2.20	$3.30	$4.40	$5.50	$8.25	$11.00	$13.75	$16.50	$19.24	$21.99

Baseline Methane Emissions: 2000 = 6.2 Tg; 2010 = 6.6 Tg; 2020 = 6.8 Tg.

Base Gas Prices ($/MMBtu): Wellhead = $2.17; Pipeline = $2.27; Citygate = $3.27

Exhibit 33: Emission Reduction For Gas Systems by Industry Segment (%)

Baseline Methane Emissions: 2000 = 6.2 Tg; 2010 = 6.6 Tg; 2020 = 6.8 Tg.
Base Gas Prices ($/MMBtu): Wellhead = $2.17; Pipeline = $2.27; Citygate = $3.27



Industry Segment	Baseline Methane Emission (Tg)		
	2000	2010	2020
Production	1.6	1.8	1.9
Processing	0.7	0.8	0.8
Transmission	2.4	2.4	2.5
Distribution	1.5	1.5	1.5
Total	6.2	6.6	6.8

As shown in this exhibit, the transmission and production sectors have both the highest emissions and the highest emission reduction potential at the energy prices and emission reduction values analyzed. In the transmission sector, emissions reductions at compressor stations and replacement of high bleed pneumatic devices dominate the analysis. In the production sector, replacement of high bleed pneumatics and emissions reductions from dehydrator vents contribute to emissions reductions. At higher emission reduction values, catalytic oxidizers on engine exhaust are a significant source of emission reduction, although the cost estimates for this technology are very preliminary.

8. U.S. COST ANALYSIS: METHANE EMISSIONS FROM LIVESTOCK MANURE

Cost curves for reducing methane emissions from livestock manure are based on recovering and utilizing methane produced at dairies and swine farms. Emissions reductions are estimated to be the amount of methane emitted from farms that can profitably recover methane at each of the energy prices and emission reduction values examined. The analysis does not include the potential to reduce reductions by shifting from liquid to dry manure management systems because such a shift would require significant changes in the design and operation of swine and dairy farms, and is considered unrealistic. Currently, regulatory strategies are being considered to reduce the impact of large livestock production facilities on water quality. The impact of these strategies on methane emissions and emissions reduction potential has not yet been estimated.

8.1 Source Summary

The anaerobic decomposition of livestock manure produces methane. Emissions are driven by the amount of manure produced, its composition and temperature, and the way the manure is managed. Managing manure using liquid or slurry systems generates significantly more methane than managing manure using dry systems. Methane produced from manure that is managed in liquid systems can be recovered and used for energy. As discussed below, the trend toward fewer and larger dairy and swine farms is leading to an increase in the use of liquid manure management systems. Consequently, baseline emissions are projected to increase. Methane emissions from dairy and swine account for about 28 and 55 percent of total emissions respectively. Other livestock account for the remaining emissions.

8.2 Scope of Emissions Reductions

The emissions reduction analysis is based on recovering methane and producing electricity on large dairy and swine farms that currently manage manure as a liquid or slurry.

Options Included in the Analysis: Three anaerobic digestion technologies (ADTs) were examined for this cost analysis:

- *Covered Lagoon System.* Large dairies and swine farms generally use liquid or slurry systems to manage manure. In these systems, a lagoon is generally used to store the manure. These lagoons, which also contain large amounts of water, promote methane production by providing an anaerobic environment. To reduce emissions, this biogas is recovered by placing an impermeable cover over the lagoon. The gas is drawn from under the cover and used to power an engine-generator and produce electricity, which is used on-site. Waste heat from the generator is used for on-farm heating needs. This technology is often preferred when manure must be flushed as part of ongoing operations.
- *Complete Mix Digester.* A complete mix digester is an engineered vessel constructed to receive swine manure daily. Typically cylindrical in shape, the digester treats the manure/water mixture for about 20 days, thereby producing methane. The digester is mixed mechanically on an intermittent basis and is heated to maintain a constant temperature. Due to the high solids content of dairy manure, complete mix digesters are not used on dairy farms. As with a covered lagoon system, the biogas produced in the digester is used to power an engine-generator. Waste heat from the generator is used for on-farm heating needs. To make a complete mix digester cost effective, the level of water usage for flushing the swine manure must be kept to a minimum. If large amounts of water must be used, a covered lagoon system will be preferred.
- *Plug Flow Digester.* A plug flow digester is an engineered vessel constructed to receive dairy manure daily. Typically constructed as a long rectangular trench, the digester treats the manure/water mixture for about 20 days, thereby producing methane. The manure is placed in one end of the digester and travels down the length of the digester over a 20 day period. The digester is heated to maintain a constant temperature. Due to the low solids content of swine manure, plug flow digesters are not used on swine farms. As with a covered lagoon system, the biogas produced in the digester is used to power an engine-generator. Waste heat from the generator is used for on-farm heating needs. In addition to the energy produced, solids can be recovered from the digester that can be

used as a soil amendment or bedding for cows. To make a plug flow digester cost effective, the manure must be scraped and placed into the digester. If manure flushing is used, a covered lagoon system will be preferred.

These technologies are chosen for the analysis because experience has shown that recovering methane from ADTs can be a highly cost-effective method for reducing emissions.

Options Not Included in the Analysis: The options not included in the analysis are as follows.

- <u>Shift to Dry Manure Management Systems</u>. Because managing manure in dry systems produces significantly less methane than managing manure in liquid or slurry systems, shifting to dry systems has the potential to reduce emissions significantly. However, such a shift would require changing fundamentally the way manure is managed on large dairy and swine farms. In particular, the land and labor requirements for spreading the manure in dry form would be substantial. Moreover, managing the manure in a dry form would require large-scale spreading of untreated manure, which could pose a threat to waterways if allowed to run off. These barriers, along with the industry trend toward large facilities and liquid systems, make such a reduction strategy unrealistic.

- <u>Other Gas Use Options</u>. In addition to producing electricity, the methane recovered from a lagoon can be used to fuel a boiler or can be flared. In most cases, producing electricity is preferred to fueling a boiler because the on-farm heat or steam needs are typically modest and can be met with the waste heat from an engine-generator system. Consequently, fueling boilers are not considered in the analysis. Although flaring is less costly than producing electricity, it produces no revenue in the absence of an emissions reduction credit or value. Additionally, once the gas is collected from the lagoon, the incremental cost of producing electricity is often less than the electricity value, such that electricity production is typically preferred to flaring. Consequently, flaring does not play a role in the analysis.

Interactions with Other Trends or Events Affecting Emissions: Manure management practices at large livestock facilities are currently undergoing increased scrutiny to assess their environmental impacts, particularly on surface and ground water. Some states have instituted moratoria on the construction of manure management lagoons at new livestock facilities. Regulatory agencies at both the state and the federal level are currently examining alternative strategies for addressing these environmental impacts. The resolution of these efforts could have an important impact on both emissions and potential emissions reductions from livestock manure.

Despite these concerns regarding manure management, the trend toward larger livestock facilities is expected to continue. Because larger facilities routinely use liquid manure management systems, this trend contributes to both increased emissions and increased potential to reduce emissions.

The cost effectiveness of reducing emissions is also influenced by energy prices because the value of the gas produced offsets the system costs. Higher energy prices make the gas more valuable, and hence make the emissions reductions more cost effective. In the future, the electricity produced by these projects may command a premium as a renewable energy source.

It should also be noted that ADTs have recently been installed to reduce odor from some swine farms. The methane captured in these systems has been used to produce electricity and heat, and has also been flared. As described below, these systems are included in the analysis by assuming that 10 percent of swine farms may install ADTs to reduce odor.

8.3 Methodology

The opportunity to reduce emissions was estimated by evaluating the ability of private decision makers (farmers) to build and operate ADTs at a profit. To develop the cost curve, a range of energy prices was evaluated along with a range of emissions reduction values. To determine profitability, the analysis estimates that in addition to the value of the energy produced, the farmer receives income equal to the emissions reduction value times the amount of methane recovered. Profitability is estimated by comparing the value of the energy and the emissions reduction to the costs of the system. The steps in the analysis are as follows:

Step 1: Define a "model" facility. Typical methane recovery and utilization systems are defined for each of the three ADTs:

- A covered lagoon system is defined to include a new lagoon, a cover for the lagoon, a methane collection system, a gas transmission and handling system, and an engine-generator. The sizes of these components are estimated based on the amount of manure handled, the hydraulic retention time for the manure required in the specific climate area analyzed, and the amount of gas produced. A new lagoon is assumed to be required in all cases even though some farms may have lagoons that are suitable for covering. This assumption makes the analysis conservative.
- A complete mix digester is defined to include the digester vessel and cover, digester heating system, methane collection system, gas transmission and handling system, and engine-generator. The sizes of these components are estimated based on the amount of manure handled. The system is designed to produce a 20 day hydraulic retention time for the manure. No costs are included for modifying the existing manure management practices to conform to the minimal water requirements of the complete mix digester.
- A plug flow digester is defined to include the digester vessel and cover, digester heating system, methane collection system, gas transmission and handling system, and engine-generator. The sizes of these components are estimated based on the amount of manure being handled. The system is designed to produce a 20 day hydraulic retention time for the manure. No costs are included for modifying the existing manure management practices to conform to the manure scraping requirements of the plug flow digester. The costs of a separator are also included so that fiber can be recovered from the digester and sold.

Step 2: Define "model" manure management practices. The amount of manure managed in liquid management systems such as lagoons determines methane emissions and methane mitigation potential. Although manure management practices can vary significantly, the large dairy and swine farms that generate most of the methane emissions and mitigation opportunities follow similar manure management practices. Large swine farms generally manage all of their manure in liquid systems and large dairy farms manage about 55 percent of their manure in liquid systems (EPA 1997). Therefore, all the manure produced on large swine farms and 55 percent of the manure produced on large dairy farms can be managed in covered lagoon systems to produce methane.

Similarly, all the manure produced on swine farms can be managed in complete mix digesters. As described above, the amount of water used to flush the swine manure would need to be reduced from the levels typically used for flushing to lagoons.

Because plug flow digesters can only accept scraped manure, the amount of manure going into a plug flow digester is typically less than the amount that can go into a lagoon. In particular, the manure from the milking parlor is always flushed, meaning that it cannot be placed into a plug flow digester. The parlor manure typically represents 15 percent of the total manure, leaving about 40 percent available to be scraped and placed into the plug flow digester.

Step 3: Develop the unit costs for the system components. The unit costs for the system components are taken from FarmWare (EPA 1997), the EPA-distributed software tool used to assess project feasibility. The unit costs and costs for typical projects are shown in Exhibit 34, Exhibit 35, and Exhibit 36 for covered lagoons, plug flow digesters, and complete mix digesters, respectively, (exhibits are presented at the end of the section, starting on page 63). As shown in the exhibits, covered lagoon systems are typically less costly to build than digester systems.

Step 4: Determine benefits to the farmer. The benefits to the farmer are the value of the energy produced and the value of the emissions reduction. The amount of electricity produced is estimated based on the amount of biogas produced and the heat rate of the engine (14,000 Btu/kWh). Biogas production at each facility is modeled using FarmWare data (EPA, 1997), and includes considerations for the amount and composition of the manure managed in the lagoon, the lagoon hydraulic retention time, the lagoon loading rate, and the impact of local temperature on the methane production rate (for lagoon systems). Biogas is assumed to be 60 percent methane and 40 percent carbon dioxide and other trace constituents. The value of the electricity is estimated using published state average commercial electricity rates (DOE, 1997), see Exhibit 37. To be conservative, these rates were reduced by

$0.02/kWh to reflect the per kWh energy savings the farmers would likely be able to negotiate with their local energy providers. This rate reduction is adopted even though the electricity produced displaces on-site electricity usage that would otherwise be purchased because experience has shown that inter-connect charges and demand charges can limit the amount of the energy savings realized.

In addition to the electricity produced, the value of heat recovery from the engine exhaust is estimated at $8/cow at dairy farms. This energy is used for heating wash water and other heating needs and displaces natural gas or propane that would otherwise be used. This value is a conservative estimate based on actual projects at dairy farms. The heat recovery value for swine farm is estimated to be 20 percent of the value of the electricity produced. This heat is particularly needed for farrowing facilities and nurseries. Less heat is often required for growing and finishing operations. The value of the emissions reduction is estimated as the amount of methane recovered times the value of the emissions reduction. For modeling purposes, the emissions reduction value is converted into an added value for the electricity produced and modeled as additional savings realized by the farmer. This conversion is performed using the methane's global warming potential (GWP) of 21, the heat rate of the engine, and the energy content of methane (1,000 Btu/cubic foot).

For plug flow digesters, fiber can be recovered using a separator and sold for about $4 to $8/cubic yard as a soil amendment. To be conservative, this analysis assumes a value of $5/cubic yard, and a fiber production rate of 1.2 cubic yards per 100 cows per day. At larger farms the cost of the separator (approximately $50,000) is more than offset by the value of the fiber, making this addition to the system profitable. The ability to realize these benefits is contingent on finding a reliable buyer for the fiber material.

Step 5: Determine break-even farm sizes. A discounted cash flow analysis was conducted for each climate division in the U.S. to estimate the smallest farm in each climate division that can profitably install and operate each of the three ADTs.[6] Swine and dairy farms are analyzed separately and farm size is measured in terms of the number of head of milk producing cows for dairies and the total number of animals for swine farms. As the number of head increases, the sizes and costs of the system components also increase, including the sizes and costs of the lagoon, the cover, and the engine-generator. The amount of manure managed and biogas produced also increase with farm size. The break-even farm size is the smallest number of animals required to achieve a net present value of zero using a real discount rate of 10 percent over a 10 year project life.[7] The electricity value in each climate division is taken as the state average minus $0.02/kWh as discussed above in Step 4. The break-even farm size is estimated for each climate division for each combination of electricity price and emissions reduction value. At higher electricity prices and emissions reduction values, smaller farms can implement the projects profitably.

Step 6: Estimate emissions reductions. National emissions reductions are estimated separately for swine and dairy farms for each combination of electricity prices and emissions reduction values using the break-even farm sizes from Step 5. First, break-even farm sizes were assigned to each county by mapping the counties into the climate divisions. Second, the portion of dairy cows and swine on farms that are greater than the break-even size is estimated for each county using the distribution of farm sizes in each county (USDC, 1995). For covered lagoon systems and complete mix digesters, emissions reductions for each county are estimated as the emissions from this portion of the dairy cows and swine.

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[6] The National Climatic Data Center (NCDC) defines up to 10 climate divisions in each of the 48 contiguous states. Each climate division represents relatively homogenous climate conditions. For purposes of this analysis, the climate division monthly average temperatures are used to estimate biogas production from lagoons. The lagoon hydraulic retention time and the maximum loading rate are set based on the area temperature as described in EPA (1997). Climate does not affect gas production from plug flow and complete mix digesters because they are heated.

[7] A 10 percent real discount rate is used to reflect the return required by the farmer for this type of investment. In particular, the ADT systems are not integral to the farmer's primary food production business, and consequently are estimated to require a higher rate of return than normal investments by the farmer.

For plug flow digesters, only scraped manure can be managed in the digester. Consequently, only manure that would otherwise be handled in a solid form will be placed in the digester. Because manure handled as a solid produces very little methane, the emission reduction from plug flow digesters would be minimal. In particular, it is considered unlikely that a dairy that currently flushes manure to a lagoon would switch to scraping manure to a plug flow digester. Therefore, emissions reductions from dairies are only estimated for covered lagoon systems.

The total emission reduction from swine farms is estimated by combining the results for the covered lagoons and the complete mix digesters. In each county, the preferred technology is assumed to be implemented. The complete mix systems tend to be preferred in colder climates where lagoons produce less methane. The emissions reductions using the preferred system are summed across all the counties and divided by the total national emissions to estimate the percent emissions reductions.

Step 7: Estimate reductions from odor control. As discussed above, some swine farms are covering their lagoons to reduce odor. The U.S. EPA AgSTAR program, which is promoting the installation of ADTs as a means of profitably reducing methane emissions, has identified odor control as the principal motivation behind several recently installed lagoon covers on swine farms. The factors driving these installations are site-specific, and are not reflected in the profitability analysis. Consequently, at swine farms the analysis assumes that a minimum emissions reduction of 10 percent will be achieved for odor control purposes. To be conservative, this 10 percent is not considered additive to the emissions reductions estimated to be profitable.

The end result of these steps is an estimate of the percent emissions reductions that can be achieved profitably for a range of energy prices and emissions reduction values. Exhibit 38 shows that emissions can be reduced by up to about 70 percent at the energy prices and emission reduction values analyzed. Also shown in the exhibit is the translation of the emission reduction values to equivalent incremental electricity prices using the engine heat rate of 14,000 Btu/kWh. Exhibit 39 shows the emissions reductions graphically versus equivalent electricity prices. For purposes of preparing this graph the average electricity price for the key states listed in Exhibit 37, less $0.02, is used as the base electricity price. Also shown in the graph are the emissions reductions for the swine and dairy industries. Assuming that costs remain constant in real terms, this cost curve (developed from 1997 data) can be applied to future years to estimate the emissions reduction that can be achieved profitably at the energy prices and emissions reduction values that apply in those years.

The assumptions and data used to implement this method are listed in the table at the end of this section.

8.4 Limitations

Site-specific factors influence the costs and benefits of recovering and using biogas from livestock manure. In particular, it is critical that the biogas recovery system be built so that it is fully integrated with the manner in which manure is managed on the farm. Because this analysis relies on model facilities and is not customized to individual farm requirements, this analysis may under- or over-estimate the profitability of emissions reductions at individual farms.

For low emissions reduction values the value of the electricity produced is the principal benefit of the ADTs. The value of the electricity savings realized depends on rates negotiated with the farm's electric service provider. Consequently, the value is considered uncertain in this analysis. It should be noted, however, that under restructuring of the electric power industry a premium value may be realized for electricity produced from renewable resources such as biogas. The potential impact of this premium is not included in this analysis.

As discussed above, the emission reduction potential is estimated based in part on the distribution of dairy and swine farm sizes as measured by numbers of head. The farm size distribution data divide the farm sizes into a relatively small number of large categories. The precision of the estimates would be improved with more refined farm size categories.

Finally, the distribution of farm sizes has changed significantly over the past 10 years, particularly in the swine industry. Since 1992, the most recent year for which farm size data are available, the trend toward smaller numbers of larger dairy and swine farms has continued. Consequently, the analysis likely under-estimates the portion of livestock on large farms as of 1997. Because emissions can more easily be reduced on large farms, the analysis also likely under-estimates the emissions reduction potential. Given that the trend toward a smaller number of larger farms is expected to continue, applying this cost curve to future baseline emissions likely under-estimates potential emissions reductions.

8.5 References

DOE, 1997. *Electric Sales and Revenue, 1996*, Department of Energy, Energy Information Administration, December, 1997.

EPA, 1997. *AgSTAR Handbook and Farmware. A Manual for Developing Biogas Systems at Commercial Farms in the United States*, Roos, K.F. and M.A. Moser eds., EPA-430-B-97-015, U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Washington, D.C., July 1997.

USDC, 1995. *1992 Census of Agriculture (CD-Rom), Geographic Area Series 1C*, U.S. Department of Commerce, Bureau of the Census, January 1995.

Exhibit 34: Livestock Manure Methane Recovery and Utilization Costs: Covered Lagoon System

Component Unit Costs

Lagoon Costs

Component	Cost
Excavation Cost /yd ($)	$1.75
Attachment Wall /yd ($)	$200
Pipe and influent box ($)	$1,700
Soil test ($)	$1,200
Foam trap ($)	$75
Very high durability cover material ($/ft2)	$0.85
Cover install labor ($/ft2)	$0.35

Utilization Equipment Costs

Component	Cost
Electricity gen ($/kW cap)*	$1,050
Electricity gen O&M ($/kWh produced)	$0.02
Electricity gen building ($/per)	$10,000
Switch gear ($/per)	$5,000
Flare ($/per)	$10,000

* Includes heat recovery

Gas Handling Costs

Component	Cost
Gas filter ($/per)	$400
Gas pump ($/per)	$800
Gas meter ($/per)	$600
Gas pressure regulator ($/per)	$100
J-trap ($/per)	$100
Manhole ($/per)	$300
Manometer ($/per)	$500

Labor and Services Costs

Component	Cost
Labor crew ($/hr)	$120
Engineering ($/job)	$25,000
Backhoe ($/hr)	$40

Pipe Costs

Component	Cost
2 in. Diameter PVC pipe ($/ft)	$1.00
3 in. Diameter PVC pipe ($/ft)	$1.50
4 in. Diameter PVC pipe ($/ft)	$2.00
6 in. Diameter PVC pipe ($/ft)	$2.25
7 in. Diameter PVC pipe ($/ft)	$4.00

Typical Project Costs

500 cow dairy (CA)

Lagoon Costs	$47,579
Gas Handling Costs	$2,380
Piping Costs	$3,306
Utilization Equipment Costs	$57,306
Labor and Services Costs	$25,000
TOTAL	**$135,571**

1000 head swine farm (NC)

Lagoon Costs	$32,690
Gas Handling Costs	$2,380
Piping Costs	$3,306
Utilization Equipment Costs	$27,925
Labor and Services Costs	$25,000
TOTAL	**$90,702**

Exhibit 35: Livestock Manure Methane Recovery and Utilization Costs: Plug Flow Digester

Plug Flow Component Unit Costs

Plug Flow Digester Costs

Component	Cost
Excavation Cost ($/yd)	$1.75
Concrete Tank & Foundation ($/yd)	$225
Curb & Grade Beam ($/yd)	$6
Pipe and influent box ($)	$800
Digester Insulation ($/panel)	$28
Very high durability cover material ($/ft2)	$0.85
Cover install labor ($/ft2)	$0.35
Foam Liner Protector ($/ft)	$1.25
Separator ($)	$50,000

Utilization Equipment Costs

Component	Cost
Electricity gen ($/kW cap)*	$1,050
Electricity gen O&M ($/kWh produced)	$0.02
Electricity gen building ($/per)	$10,000
Switch gear ($/per)	$5,000
Flare ($/per)	$10,000

* Includes heat recovery

Hot Water Transmission Costs

Component	
Trench/Sand/Liner ($/ft)	$2.3
Manometer ($)	$500
Hot Water Pipe ($/ft)	$3.5

Labor and Services Costs

Component	Cost
Labor crew ($/hr)	$120
Engineering ($/job)	$25,000
Backhoe ($/hr)	$40

Gas Handling Costs

Component	Cost
Gas filter ($/per)	$400
Gas pump ($/per)	$800
Gas meter ($/per)	$600
Gas pressure regulator ($/per)	$100
J-trap ($/per)	$100
Manhole ($/per)	$300
Manometer ($/per)	$500

Pipe Costs

Component	Cost
2 in. Diameter PVC pipe ($/ft)	$1.00
3 in. Diameter PVC pipe ($/ft)	$1.50
4 in. Diameter PVC pipe ($/ft)	$2.00
6 in. Diameter PVC pipe ($/ft)	$2.25
7 in. Diameter PVC pipe ($/ft)	$4.00

Typical Project Costs for a 500 Cow Dairy (CA)

Digester Costs	$38,721
Hot Water & Gas Handling Costs	$2,804
Piping Costs	$1,163
Solid Separator	$50,000
Utilization Equipment Costs	$42,869
Labor and Services Costs	$25,000
TOTAL	**$160,557**

Exhibit 36: Livestock Manure Methane Recovery and Utilization Costs: Complete Mix Digester

Component Unit Costs

Complete Mix Digester Costs

Component	Cost
Excavation Cost /yd ($)	$1.75
Concrete Tank & Foundation ($/yd)	$225
Curb & Grade Beam ($/ft)	$6
Pipe and influent box ($)	$1,700
Pipe/Fit/Rack/Labor ($/ft^3 digester volume)	$.10
Very high durability cover material ($/ft2)	$0.85
Cover install labor ($/ft2)	$0.35

Utilization Equipment Costs

Component	Cost
Electricity gen ($/kW cap)*	$1,050
Electricity gen O&M ($/kWh produced)	$0.02
Electricity gen building ($/per)	$10,000
Switch gear ($/per)	$5,000
Flare ($/per)	$10,000

* Includes heat recovery

Hot Water Transmission Costs

Component	
Trench/Sand/Liner ($/ft)	$2.3
Manometer ($)	$500
Hot Water Pipe ($/ft)	$3.5

Labor and Services Costs

Component	Cost
Labor crew ($/hr)	$120
Engineering ($/job)	$25,000
Backhoe ($/hr)	$40

Gas Handling Costs

Component	Cost
Gas filter ($/per)	$400
Gas pump ($/per)	$800
Gas meter ($/per)	$600
Gas pressure regulator ($/per)	$100
J-trap ($/per)	$100
Manhole ($/per)	$300
Manometer ($/per)	$500

Pipe Costs

Component	Cost
2 in. Diameter PVC pipe ($/ft)	$1.00
3 in. Diameter PVC pipe ($/ft)	$1.50
4 in. Diameter PVC pipe ($/ft)	$2.00
6 in. Diameter PVC pipe ($/ft)	$2.25
7 in. Diameter PVC pipe ($/ft)	$4.00

Typical Project Costs for a 1000 head Swine Farm (NC)

Complete Mix Digester Costs	$57,141
Gas Handling Costs	$2,804
Piping Costs	$1,163
Utilization Equipment Costs	$36,000
Labor and Services Costs	$25,000
TOTAL	**$122,110**

Exhibit 37: 1996 Average Commercial Electricity Rates

Key states in **BOLD**

State	$/kWh	State	$/kWh
Alabama	0.065	Montana	0.055
Alaska	0.096	Nebraska	0.055
Arizona	**0.080**	Nevada	0.066
Arkansas	0.067	New Hampshire	0.113
California	**0.098**	New Jersey	0.103
Colorado	**0.059**	**New Mexico**	**0.079**
Connecticut	0.103	New York	0.121
Delaware	0.070	**North Carolina**	**0.064**
Florida	**0.066**	North Dakota	0.061
Georgia	0.072	Ohio	0.077
Hawaii	0.130	Oklahoma	0.058
Idaho	0.043	Oregon	0.052
Illinois	**0.080**	Pennsylvania	0.083
Indiana	**0.059**	Rhode Island	0.101
Iowa	**0.065**	South Carolina	0.064
Kansas	0.067	South Dakota	0.066
Kentucky	0.052	Tennessee	0.066
Louisiana	0.071	**Texas**	**0.067**
Maine	0.104	**Utah**	**0.059**
Maryland	0.068	Vermont	0.101
Massachusetts	0.099	Virginia	0.059
Michigan	0.079	**Washington**	**0.049**
Minnesota	0.061	West Virginia	0.057
Mississippi	0.071	**Wisconsin**	**0.057**
Missouri	0.060	Wyoming	0.051

Source: DOE (1997)

Note: To estimate the value of the electricity produced on each farm, $0.02/kWh was subtracted from the prices listed in this exhibit. See text.

Exhibit 38: Emission Reduction For Livestock ManureManagement (%)

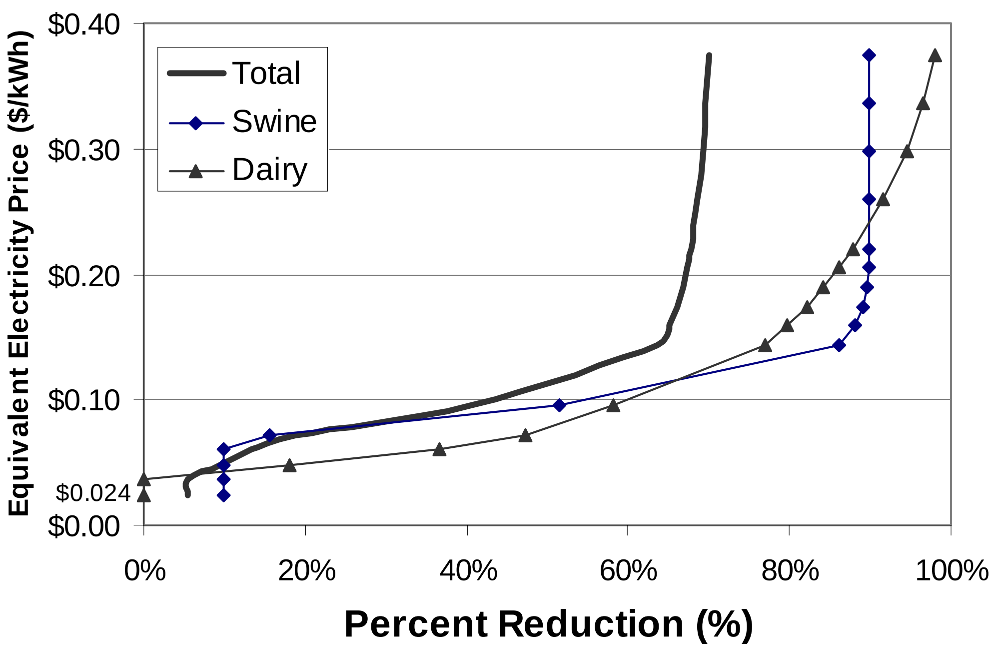
All Years	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
Energy Price	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
50% of Base	5%	5%	5%	8%	11%	23%	43%	60%	64%	65%	66%	67%
75% of Base	5%	7%	10%	14%	26%	35%	57%	62%	65%	66%	67%	68%
100% of Base	**9%**	**12%**	**15%**	**28%**	**36%**	**44%**	**60%**	**64%**	**65%**	**67%**	**68%**	**69%**
125% of Base	13%	17%	29%	36%	45%	52%	62%	65%	66%	67%	68%	69%
150% of Base	19%	30%	37%	45%	53%	59%	64%	66%	67%	68%	69%	69%
200% of Base	41%	46%	53%	60%	62%	64%	66%	67%	68%	69%	70%	70%
300% of Base	63%	65%	66%	67%	67%	68%	69%	69%	70%	70%	70%	70%

Reduction Value ($/kWh)	**Emission Reduction Value ($/ton of Carbon Equivalent)**											
	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
Incremental Electric Price	$0.000	$0.015	$0.031	$0.046	$0.062	$0.077	$0.115	$0.154	$0.192	$0.231	$0.269	$0.308

Baseline Methane Emissions: 2000 = 3.2 Tg; 2010 = 3.9 Tg; 2020 = 4.6 Tg.
Base Electricity Prices Vary by State – See Exhibit 37

Exhibit 39: Emission Reduction Versus Equivalent Electricity Price For Livestock Manure Management (%)

Baseline Methane Emissions: Total: 2000 = 3.2 Tg; 2010 = 3.9 Tg; 2020 = 4.6 Tg
Dairy: 2000 = 0.9 Tg; 2010 = 1.1 Tg; 2020 = 1.3 Tg
Swine: 2000 = 1.7 Tg; 2010 = 2.1 Tg; 2020 = 2.6 Tg.
Equivalent Base Electricity Price Shown as $0.048/kWh (See Text)



Summary of Data and Assumptions Used in the Livestock Manure Analysis

Element of the Analysis	Current Values	Discussion
Livestock Population	Historical: USDA statistical reports (USDA, Various)	These data are used to estimate the baseline methane emissions.
Farm-size Distribution	From 1988 and 1992 *Census of Agriculture* (USDC, 1991 & 1995).	The 1992 distribution is used for the key states. When released in 1999, the 1997 Census data should be used.
Typical Animal Mass (TAM)	Dairy: 640 kg/head Swine: 150 kg/head Source: ASAE (1995)	ASAE values are updated periodically.
Volatile Solids (VS) production	Dairy: 10 kg/head/day Swine: 8.5 kg/head/day Source: ASAE (1995)	Dairy cow VS production increases as milk production and intake increase. Swine VS production is expected to increase in the future as production is consolidated onto larger farms. These increases are not reflected in the analysis.
Manure Management System usage Maximum Methane Production Potential (B_0) Methane Conversion Factor for each Manure Management System (the portion of the B_0 that is realized)	The distribution of manure management system use and the values for B_0 are taken from Safely et al. (1992). The manure management data were updated for key states based on discussions with manure management experts. The B_0 values are: Dairy: 0.24 m^3/kgVS Swine: 0.36 – 0.47 m^3/kgVS The methane conversions factors (MCFs) are from Safley et al. (1992) and Hashimoto and Steed (1992). The MCFs range from 10-65% for liquid slurry systems. Lagoons are estimated to have a MCF of 90%.	These data are used to estimate the baseline methane emissions from manure management, and hence are also used to estimate the emissions reductions achieved based on the break-even farm sizes. Recent trends toward the increasing use of liquid systems and lagoons on large farms is not reflected in the data, possibly biasing downward the emissions estimates. The basis for estimating the MCFs remains weak. Improved MCF values would strengthen the estimates of both the emissions and the emissions reductions.
Value of electricity produced	Average 1996 commercial state electricity prices (DOE, 1997) minus \$0.02/kWh are used as the value of the electricity produced and used on site.	The electricity value is a critical driver in the analysis in the absence of value for the emissions reduction. The value is project specific and depends upon negotiations between the farmer and the electricity provider.

Element of the Analysis	Current Values	Discussion
Methane recovery system design parameters	Lagoon Depth: 15 ft. Lagoon Side Slopes: 2 Percent of manure flushed to the lagoon (used to size the lagoon): 90% Percent of VS flushed to the lagoon (used to estimate biogas production): 75% Engine-generator heat rate: 14,000 Btu/kWh	Data based on AgSTAR experience designing and building covered lagoon systems.
Methane production rate	Estimated for each climate division using the modeling kinetics in FarmWare (EPA, 1997).	Methane production depends not only on the design of the facility but on the manner in which it is operated as well. Methane production estimates assume that the facility is operated to achieve its methane production design level.
Lagoon system unit costs	Unit costs are listed in Exhibit 34.	Data from EPA (1997).
Discounted cash flow parameters	Real Discount Rate: 10% Tax Rate: 40% Depreciation: straight line Project Duration: 10 years	Financial parameters based on AgSTAR experience designing and building covered lagoon systems.